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REACTIVE POWER AND SECURITY STUDIES IN AN OPEN POWER MARKET

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CERTIFICATE OF ORIGINALITY

I hereby declare that this thesis is my own work and that, to the best of my knowledge and belief, it reproduces no material previously published or written nor material which has been accepted for the award of any other degree or diploma, except where due acknowledgement has been made in the text.

______________________________(Signed)

_____________Xu Jun LIN__________(Name of student

DEDICATION

To my parents,

Zheng Ming LIN and Xin Hong WU

and my wife,

Yu Zhen CHEN

SYNOPSIS

The traditional regulated and monopoly structure of power supply industry throughout the world is eroding into an open-access and competitive environment. Integrated generation, transmission and distribution functions in the power supply chain are unbundled. Responsibility of maintaining reliability and security has been transferred to an organization generally referred as independent system operator, which is independent of different businesses entities.

Delay of transmission facility construction, unpredictable pattern of load increase and economic incentives have made system operation conditions more stressed than ever before. Various stability problems have been recognized as the main threats to secure system operation. Security, especially transient security, constrained system operation is a difficult task facing a system operator in the electricity market environment. It is the first major topic discussed in the thesis. A systematic approach for transient security enhancement with single and multiple contingencies under the electricity market environment is developed. The proposed corrected hybrid method is an effective transient stability assessment method. The stability index called the corrected transient energy margin given by the method bears a linear relationship, within a useable range, with important control variables such as generation exchanges. An optimal rescheduling scheme taking generator bids into account to enhance transient security for single potential unstable contingency is proposed. The methodology also responds to price signals since it is important in the deregulated environment. Difficulties arise when several unstable contingency have to be enhanced. Different candidate contingencies may motivate different rescheduling strategies because the critical generator group is different in each case, or the sensitivity of the stability margin to power exchanges between generators is different. A global index, which reflects the global transient security enhancement and deals with trade-off between contingencies, is proposed in the thesis. Using this index and generator bid information, a transient security enhancement approach for multi-contingencies is also developed.

The second major topic investigated in the thesis is reactive power management in the electricity market environment. Reactive power support services are crucial for secure operation of electric power systems. To improve competition and efficiency of provision of reactive power support and voltage control services, procurement and charge of reactive power support and voltage control services should be unbundled from electricity service and transmission service. Costs of different suppliers should be precisely identified and properly compensated for and different users should only be charged exactly that part of the requirement caused by them. Different from active power, the objective of reactive power support procurement is not unique. In different power systems, the objectives could be different and are dependent on the structures and operating characteristics of the systems concerned. Subsequently, methods used to allocate reactive power support costs to consumers are different. Three approaches have been developed in this thesis to solve the problem of procurement and charge of reactive power services. Regarding cost allocation, one approach considers that some reactive power support costs should be the responsibility of generators while the other two assume all should be allocated to the loads. The latter two approaches use the Aumann-Shapley cost allocation method to make the allocation process more economically efficient and equitable. Reactive power optimization taking voltage instability into account is also investigated in the thesis. Increased loading and exploitation of power transmission networks appear to have created a special voltage security problem, namely voltage stability. Traditional voltage profile criteria are not sufficient for electric power systems concerning the voltage stability problem. A reactive optimal power flow formulation is proposed to minimize reactive power support costs while respecting the voltage stability margin requirement.

PUBLICATIONS ARISING FROM THE THESIS

During my study programme, ten papers have been produced. Among them, six journal papers have been published and four conference papers have been presented. A detailed list is given as follows:

Journal papers published:

A. X.J. Lin, C.W. Yu, N. Xu, C.Y. Chung, and H. Wu, “Reactive power service cost allocation using the Aumann-Shapley method”, *IEE Proceedings: Generation, Transmission, and Distribution*, Vol. 153, No. 3, pp.540-546, 2006.

B. X.J. Lin, C.W. Yu, and A.K. David, “Optimum transient security constrained dispatch in competitive deregulated power systems”, *Electric Power Systems Research*, Vol. 76, No. 4, pp. 209-216, 2006.

C. X.J. Lin, C.W. Yu, A.K. David, C.Y. Chung, and H. Wu, “A novel market-based reactive power management scheme”, *International Journal of Electrical Power and Energy Systems*, Vol. 28, No. 2, pp. 127-132, 2006.

D. X.J. Lin, C.W. Yu, and C.Y. Chung, “Pricing of reactive support ancillary services”, *IEE Proceedings: Generation, Transmission, and Distribution*, Vol. 152, No. 5, pp. 616-622, 2005.

E. X.J. Lin, A.K. David, and C.W. Yu, "Reactive power optimisation with voltage stability consideration in power market systems", *IEE Proceedings: Generation, Transmission, and Distribution,* Vol. 150, No. 3, pp. 305-310, 2003.

F. A.K. David and Xujun Lin, "Dynamic security enhancement in power-market systems", *IEEE Transactions on Power Systems*, Vol. 17, No. 2, pp. 431-438, 2002.

Conference papers presented:

G. X.J. Lin, C.W. Yu, C.Y. Chung, and N. Yang, "Reactive power pricing using the Aumann-Shapley method", *Proceedings of the Regional Inter-University Postgraduate Electrical and Electronic Engineering Conference (RIUPEEEC 2005)*, Hong Kong, P.R. of China, July 2005, Paper No. 154.

H. X.J. Lin, C.W. Yu, A.K. David, and C.Y. Chung, "A generalised approach to transient security enhancement in power markets", *Proceedings of the 2nd International Conference on Electric Utility Deregulation, Restructuring and Power Technologies (DRPT 2004)*, Hong Kong, P.R. of China, April 2004, DRPT-75.

I. X.J. Lin, C.W. Yu, A.K. David and C.Y. Chung, "Market mechanism for reactive power management", *Proceedings of 2003 International Conference on Advances in Power System Control, Operation and Management*, Hong Kong, P.R. of China, November 2003, pp. 593-600.

J. X.J. Lin, C.W. Yu, A.K. David, and C.Y. Chung, “Transient security enhancement in power markets”, *Proceedings of the Regional Inter-University Postgraduate Electrical and Electronic Engineering Conference (RIUPEEEC 2003)*, Hong Kong, P.R. of China, August 2003, Paper No. A1-7.

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A-S	Aumann-Shapley
COI	Center of Inertia
CTEF	Corrected Transient Energy Function
CTEM	Corrected Transient Energy Margin
CTKE	Corrected Transient Kinetic Energy
CTPE	Corrected Transient Potential Energy
DISCO	Distribution Company
EPRI	Electric Power Research Institute
FACTS	Flexible Alternative Current Transmission Systems
FERC	Federal Energy Regulatory Commission
GENCO	Generation Company
GI	Global Index
HVDC	High Voltage Direct Current
ISO	Independent System Operator
NERC	North American Electric Reliability Council
OPF	Optimal Power Flow
QSS	Quasi Steady State
SEP	Stable Equilibrium Point
SQP	Sequential Quadratic Programming
SVC	Static VAr Compensator
TEF	Transient Energy Function
TEM	Transient Energy Margin
TKE	Transient Kinetic Energy

TPE	Transient Potential Energy
TSA	Transient Stability Assessment
VSI	Voltage Stability Index
VSM	Voltage Stability Margin

1 INTRODUCTION

1.1 Power Industry Deregulation

The electric power industry was dominated over the years by large utilities, which were engaged in all the activities of generation, transmission and distribution of power. These vertically integrated entities were usually granted monopoly status in defined franchise areas with the obligation to serve all consumers within those territories. Cost-of-service regulation was developed to protect consumers from potential monopolistic abuses while ensuring a fair rate return to utilities. The traditional structure of the industry was based on the economic theory that electric power production and delivery were natural monopolies, and that large centralized power plants were the most efficient and inexpensive means for producing electric power and delivering it to customers.

However, over the past two decades the electric power industry has undergone fundamental changes. The significant feature of these changes is to allow for competition among generators of electricity and to create market conditions in the industry, which are seen as necessary to increase the efficiency of electric energy production and distribution, and to lower prices. This transition towards a competitive power market is commonly referred as deregulation or restructuring. As a worldwide phenomenon, the driving forces behind deregulation varied from country to country, coming from many resources that range from political reform, regulatory failures, high tariffs, managerial incompetence, global economic opportunities, the rise of environmentalism, and the lack of public resources for investment.

Different approaches have been adopted for the process of deregulation in different regions. A common theme in a deregulated power system is the separation of generation, transmission and distribution, known as unbundling. Power generation has become a competitive business after restructuring. Generation companies can sell energy through bilateral contracts with customers or by bidding for short-term energy supply in a spot market [8][101]. Transmission and distribution activities remain regulated due to their natural monopoly characteristics. The transmission sector is viewed as the centerpiece of deregulated systems. Open and non-discriminatory access to the transmission system is the key requirement for facilitating competitive markets. To guarantee a level playing field for all generators and customers to access the transmission network, the transmission system operator is required to be independent from market participants. The *independent system operator* (ISO) has acquired a central coordinating role and carries out the important responsibility of ensuring system reliability and security. It manages system operations, such as scheduling and operating the transmission-related services. The ISO also has to ensure a required degree of quality and safety, provide corrective measures when faced with contingencies, and undertake several other functions. Depending on market architecture, the ISO may or may not also manage market administration, energy auctions and unit commitment functions.

In the new electricity market environment, many challenges to power system management, planning, operations and control have arisen, such as generation investment and expansion planning, transmission investment and expansion planning, pricing, bid-based dispatching, congestion management, and ancillary services procurement and pricing. Much research work has been done to ensure that deregulated power systems achieve a balance between economics and security so as to maximize the social welfare, although this objective has not always been achieved. In the last two decades, numerous books, papers and research reports have addressed many different problems in the emerging electricity market environment, but many problems remain unsolved and further research is needed. It is not possible to discuss, or even enumerate, all the problems arising from the power industry restructuring in this thesis. Two specific research areas, namely transient security constrained system dispatching and reactive power management, will be the focus of the studies presented in this thesis. Different from many other research areas in the electricity market environment, research work in these two areas are at a early stage, and systematic methodologies have not yet been developed. Given this background, a review of existing research work in these two areas will first be presented in the following sections.

1.2 Transient Security Considerations in Restructured Power Systems

Generally speaking, power system security can be defined as the absence of risk of system operation disruption. In practice, it is defined as the ability of the system to withstand without serious consequences any one of a list of "credible incidents" (contingencies)[30]. Typical contingencies include loss of generating units or transmission components either spontaneously or preceded by short circuits. The formal introduction of the concept of security as a framework for planning and operating power systems emerged in 1967 [40]. "Classification into power system operating states" proposed in [41][50] provides a conceptual basis for security assessment and enhancement. The assumption that system states other than the normal state are unacceptable is the guideline for making security related decisions.

Maintaining system security is the important and routine work of power system operators, and certainly there is no exception in the new electricity market environment. In a vertically integrated system, the utility company owns all sectors of the power supply chain, and hence, issues concerning individual interests of separated business entities in making security related decisions do not arise. However, in a deregulated power system where generation, transmission and distribution are separated entities in terms of ownership and management, the interests of separated companies have to be coordinated in making security related decisions. Moreover, bilateral contracts and multi-lateral contracts among market participants have to be dispatched in the new environment. This matter does not exist in traditional power system dispatching. The ISO who is responsible for system security must follow a set of market related rules which are agreed upon by market participants in implementing security control actions. Security control methodologies developed for the traditional power system cannot be applied to a deregulated power system without some modifications.

Furthermore, the system operating status tends to be more severe in the deregulated environment. First, power flow patterns change more frequently. In the deregulated environment, in the long run incentives are provided for suppliers to locate closer to loads. While in the short term, bid-based dispatch leads to unconventional operating challenges, since dispatch levels of suppliers depend on their bid prices which can be set strategically, and as a result, are variable. If choice of suppliers by customers is permitted, generation and load patterns are likely to change more frequently due to the switching of suppliers. All these will make the power flow pattern change more frequently and more significantly in a market environment. Secondly, since the existing transmission systems were not originally designed for handling supply and demand patterns in competitive markets some parts of network will be utilized in ways different from those originally planned or historically used. New transmission bottlenecks may be created and some existing transmission constraints may be binding more often and with more economic significance. Thus measures to relieve congestion become more demanding. Thirdly, in some deregulated electricity markets, large customers are permitted to buy power from suppliers directly. An assessment report made by *Electric Power Research Institute* (EPRI), USA mentions that large power transactions have increased significantly and the distance of power transactions is becoming longer. Hence, higher transfer capability will be required and the system will be operated more close to security boundaries in the deregulated environment than before. Fourthly, transmission investment is expected to become more prudent in the market environment due to absence of well-defined responsibility. All these factors make the system security problem more severe in the market environment, and hence deserve more attention.

There are two components of security analysis. Static security analysis involves steady-state analysis of post-disturbance conditions to ensure that thermal and voltage constraints are not violated; the hidden assumption being that the transition process from pre-disturbance to post-disturbance has completed. Secondly, dynamic security analysis where the transition itself is of interest and various stability problems have to be examined [5][73][74].

1.2.1 Stability analysis in general

Stability analysis is an integrated component of security assessment. Prior to discussing a specific stability problem, the different kinds of disturbances that happen in power systems should be declared [73][74]. A disturbance in a power system represents a sudden change or a sequence of changes in one or more of the operating parameters of the system, or in one or more of the operating quantities. Disturbances may be large or small. Small disturbances in the form of load changes occur continually and the mathematical model describing system dynamics may be linearized for the purpose of analysis. Large disturbances are more severe and linearization is generally improper for stability analysis under such circumstances. A disturbance may be a short circuit or loss of a critical generation/transmission component. Power system stability is generally defined as "the ability of an electric power system, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical disturbance, with most system variables bounded so that practically the entire system remains intact" [74]. Classification of stability is illustrated in Figure 1-1:

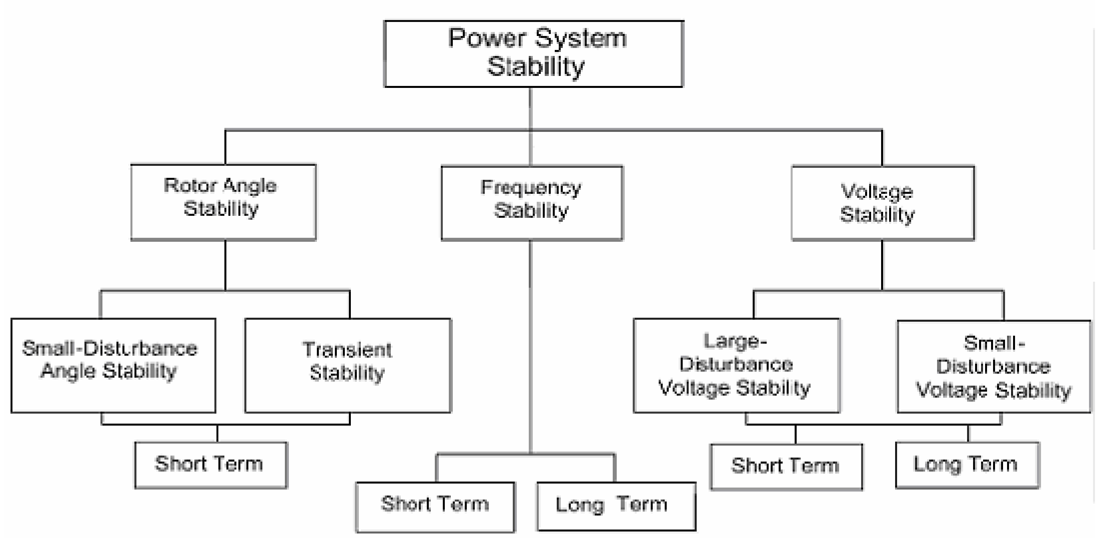

Figure 1-1. Classification of power system stability [74]

Since both transient stability and voltage stability are include in this thesis, a brief survey on these two topics will first be made.

1.2.2 Transient stability analysis

Transient stability refers to the ability of a power system to maintain synchronism when subjected to a severe disturbance such as a fault on a transmission line. The resulting system response involves large excursions of generator rotor angles and is influenced by the nonlinear power-angle relationship. The time frame of interest in transient stability studies is usually 3 to 5 seconds following the disturbance. Many advanced methods have been developed for *transient stability assessment* (TSA) including more efficient time-domain simulation [44], *transient energy function* (TEF) methods [52][54][55] and single machine equivalent techniques [81][128]. Time-domain methods provide the most accurate and reliable results and, arguably, have unlimited modeling capability. However, they suffer from two major drawbacks: they are inherently slow because they require numerical integration of large families of dynamic equations, and they do not provide any information about the degree of stability (or instability) of the system. The TEF method is an alternative tool for dynamic stability evaluation and significant advancements have been achieved in the last two decades. The main attractions of the TEF approach are computational speed and the ability to provide a transient stability margin or index. However, the method sometimes fails to yield a practical result because of non-convergence problems encountered in attempting to compute the relevant “unstable equilibrium point”, especially in the case of stressed systems. This difficulty has been overcome in the hybrid approach which combines time-domain simulation and transient energy analysis [87]. First, time-domain integration is performed and then a *transient energy margin* (TEM) is estimated as the system stability index. Another significant advantage claimed for the hybrid method is its ability to incorporate detailed generator and other component representations. Unfortunately, however, it has been observed that the variation of TEM computed by the hybrid method often exhibits erratic non-linearity around the critical value when plotted against some key system operating parameters. This limits the value of the method as a control tool for stability enhancement, since the changes of critical generator output or interface power flow predicted as necessary for stabilization, will be unreliable. The corrected hybrid method [43][45][46][47], which combines time-domain simulation and the *corrected transient energy function* (CTEF), is an effective dynamic security assessment method. The CTEF is really a method for computing a stability index called the *corrected transient energy margin* (CTEM). An important feature of the CTEM is that it bears a linear relationship, within a useable range, to important control variables such as generator power exchanges [43][46][47]. This means that the CTEM value can be conveniently changed from an undesirable to a desirable magnitude by linear adjustments of control variables, for example rescheduling generation between two units.

1.2.3 Voltage stability analysis

Various voltage stability definitions are available in publications [26][30][68][69][74][118]. A simple description of voltage instability from [30] is quoted here: "*Voltage instability stems from the attempt of load dynamics to restore power consumption beyond the capability of combined transmission and generation system*". From this statement, we can see voltage instability is load-driven phenomenon. The term voltage collapse is also often used. It is the sequence of events accompanying voltage instability which leads to a blackout or abnormally low voltages in a significant part of the power system. Theoretical base for voltage stability analysis is bifurcation theory. Bifurcation theory [108] assumes that system parameters vary slowly and predicts how the system typically becomes unstable. Two types of bifurcations are mainly responsible for voltage instability namely saddle-node bifurcation and limit induced bifurcation. The main idea is to study the system at the threshold of instability. Regardless of the size or complexity of the system model, there are only a few ways in which it can become unstable and bifurcation theory describes these and the associated calculations. Saddle-node bifurcation can be shown to be generic in power systems. Limits, especially generator reactive power limits can instantly change stability status [39]. Voltage stability analysis methods can be classified into static methods [15][28][98] and time domain simulation methods (multitime-scale simulation [73][106] for short-term analysis and *quasi steady state* (QSS) simulation [31][77][107] for long-term analysis). Static methods focus on the existence of long-term post-contingency equilibrium. Time simulation methods are more accurate and demand more computations.

Similar to transient stability assessment, there exist various *voltage stability index* (VSI) to predict proximity to voltage collapse. Among them, the minimum singular value in [119], later pursued in [62], and the condition number in [96] of system Jacobian intend to provide a measure of how far the system is away from the point at which the system Jacobian becomes singular. The performance index proposed in [115][116] is based on the angular distance between the current stable equilibrium point and the closest unstable equilibrium point in a Euclidean sense. The performance index proposed in [36][99] measures the energy distance between the current stable equilibrium point and the closest unstable equilibrium point using an energy function. These performance indices can be viewed as providing a measure regarding the "distance" between the current operating point and the bifurcation point. Note that the performance indices mentioned above are defined in the state space of power system models instead of in the parameter space. There are also indices associated with system operating parameters and this type of VSI is always referred as *voltage stability margin* (VSM). For a particular operating point, the amount of additional load in a specific pattern of load increase that would cause a voltage collapse is called the loading margin to voltage stability. Loading margin is the most basic and widely accepted index of voltage stability. There are several choices in defining the loading margin. The change in loading can be measured either by the sum of the absolute changes in load powers or by the square root of the sum of squares of the changes in load powers. Often loads are assumed to have constant power factor and in that case the change in loading can be measured by the changes in real power only. Another useful choice for constant power factor loads is to measure the change in loading by the sum of absolute changes in load powers, which is the technique used in this thesis. A version of a loading margin measures the maximum amount of power transfer between two areas when studying the transfer capability between areas.

Different methods have been developed to calculate VSM, including direct methods, continuation methods and optimization-based methods. Direct methods [1][16][17], also known in power system applications as Point of Collapse methods, were originally developed to compute singular bifurcation points of nonlinear systems [108]. When system parameters change smoothly, the direct method makes very accurate predictions of proximity to collapse [1][17]. An obvious disadvantage with this technique is the high computational cost, as the number of equations increases is twice the system steady state equations. Moreover, it requires good initial conditions. Another disadvantage of the direct method is that it can only determine a collapse point associated with system singularities (saddle-node bifurcations). Voltage collapses related to control limits, particularly generators reaching reactive power limits [16][39][93], cannot be detected using this technique, and hence giving incorrect answers in many practiced case [16]. Continuation methods [2][16][23] are iterative numerical techniques used to detect bifurcation by tracing the bifurcation diagram and indirectly detecting bifurcations. In power systems, continuation methods typically trace the voltage profile of system up to the maximum loading point of the system.

Continuation methods consist of two or three steps. The first part is predictor step, the second is a corrector step and the third is a parameterization step. The last step can be omitted in some algorithms. These methods have the advantage that more information is obtained about the system behavior, but they may be computationally expensive, especially in large systems. Optimization based methods [28][70][83][94][95][100][103][104] formulate the collapse point computation as an optimization problem. Early attempts can be found in [28][94][95]. Stating the collapse problem as an optimization problem allows for the use of several well-known optimization techniques to compute the collapse point, as discussed in [83]. One particular technique that is especially appealing due to its limit handling capabilities is the Interior Point Method, which has been successfully applied to the computation of the collapse point [70][100]. The ability of optimization based methods to indicate appropriate control actions on certain system variables to improve the stability margin were discussed in [103][104].

1.2.4 Transient security constrained generation rescheduling

How to maintain power system reliability in the electricity market environment is a matter of much concern. It is generally believed the power industry restructuring will have a negative effect on the system reliability. It is well known that a significant deterioration in reliability levels could have very severe social and economic consequences that directly counter the benefits of decreased energy costs brought about by competition. Security is an important part of reliability, as defined by *North America Energy Reliability Council* (NERC) [120], and is mainly concerned with power system operation.

In the electricity market it is necessary to schedule generators based on bids from generation companies. This could lead to security related issues and checks and balances are needed. While economic efficiency is becoming increasing important in the electricity market environment, system security should not be overlooked and must be given overriding attentions.

Much research work has been done on the system dispatch with operating constraints for both the traditional and the restructured power systems. In the electricity market environment this problem is referred to by some researchers as congestion management ([13][14][21][22][34][48][49][57-59][64][75][88][97][102][110][111][123-125][127]). In fact, congestion management is not a new problem, the only change is that the system dispatch is now bid-based rather than cost-based. Certainly, system dispatch while observing security constraints is more challenging than that with operating constraints only. Security constrained dispatch or security constrained congestion management has not yet been well studied in the electricity market environment, and only some preliminary research has been done [24][35][89][109][130]. Moreover, although some research work has been done on transient security constrained generation dispatching for the traditional power industry [20][53][60][76][79][82][90][129], less attention has been paid to the same problem in the new electricity market environment. To the best of our knowledge, the only preliminary research work been done in this aspect is in references [38][84][85][112][113].

Certainly, the problem of transient security constrained generation dispatch or generation rescheduling for transient security enhancement is a very difficult and challenging topic. Up to now, a systematic framework is not available. This stimulates us to develop a general framework for this problem with single and multiple contingencies in this PhD study. This work is presented in Chapters 2 and 3 and forms the first part of this thesis.

1.3 Reactive Power Management and Related Issues

The second part of this thesis is concerned with reactive power related issues in the electricity market environment, which are tightly related to voltage stability. Broadly speaking, these issues could be called reactive power management.

It is well known that reactive power plays an important role to support active energy transfer by maintaining system voltages within proper limits. In the vertically integrated electricity industry, the costs of reactive power support are included in the bundled electricity prices that retail customers pay. There are no economic signals for reactive power services, and reactive power support is determined by the judgments of operators. This practice is problematic in the new power markets characterized by the separation of generation, transmission and distribution where incurred costs of different reactive power suppliers should be identified and properly compensated. The ISO, as the power market facilitator, is responsible for coordinating reactive power service from generation and transmission facilities.

How to properly manage reactive power is a problem of extensive concern in the electricity market environment. Many debates arise and different solutions have been proposed. The most fundamental and yet important problem is: "How should reactive power be procured, by a competitive market just like that for active power, or by other means?" This is still a very controversial issue around the world. It is generally believed that reactive power services cannot be procured completely through a competitive bid-based market due to its local characteristic. Reactive power support can be procured from many different sources. Hence, some form of competition should be introduced since reactive power resources are owned by different entities in the electricity market, and as a result, the traditional way for procuring reactive power is no longer suitable and new schemes have to be developed. In fact, some researches have been carried out in this area since 1990s. Hao [67] proposed two methodologies for reactive power management and pricing. One was based on reactive power performance standards for generator and load customers and the other was based on the local reactive power market concept. Bhattacharya and Zhong constructed a reactive power bid curve of a generator in [9] and on this basis a competitive market mechanism is further developed in [132]. However, research work in this area is still very preliminary and further research is needed. Given this background, a framework for reactive power management will be investigated in this thesis.

No matter how reactive power support is procured, the problem of reactive power pricing or reactive power cost allocations will always be encountered, although different procurement schemes may be appropriate for different reactive power sources. In fact, analyzing the costs of providing reactive power services and establishing an appropriate pricing structure are important both financially and operationally for the deregulated electric industry. First, right price signals will facilitate transmission access and improve economic efficiency. With the proper costing and pricing of reactive power, transmission users will have the ability to make intelligent decisions about economic activities such as energy transactions, investments, and asset utilization. Second, the efficiency and reliability of system operation will be improved when well-balanced reactive power is available to support the transmission network since active power losses in the transmission system will be reduced by properly distributing reactive power sources. Last, the voltage profiles will be improved which, in turn, will reduce the incidents caused by high and low voltage problems. In the last two decades, much work has been done on reactive power pricing and reactive power cost allocations. Many publications on reactive power pricing build on the marginal cost theory, which has been applied in the spot pricing of real power [18]. An early attempt at this approach can be found in [6]. A decoupled *optimal power flow* (OPF) model was proposed for active and reactive power pricing in [42]. In-depth theoretical discussions on applying the concept of marginal cost for the real time pricing of reactive power was provided in [7]. Detailed cost models of reactive power support can be found in [78] and a similar approach based on the opportunity cost of dispatching reactive power from generators was adopted in [32][33]. However, as pointed out in [66][67], the application of marginal reactive power pricing may not be practical due to the volatility and erratic behavior of such prices. Moreover, marginal cost pricing is subject to the problem of reconciling marginal cost prices with the requirement to recover costs. Another approach is to formulate the reactive power pricing as a reactive power support cost allocation problem. Reactive power tracing [20], graph theory [126] and modified Y-Bus method [25] are in this category. These methodologies attempt to charge system participants by determining the reactive power that each generator contributes to each individual load. However, real and reactive power flow coupling in a transmission network makes contribution factor calculation using these methods subjective to some extents. Hence, further research work on reactive power pricing and cost allocations is still very necessary and this is one of the focuses of this thesis.

As already mentioned before, one of the major purposes of procuring reactive power is for maintaining or improving voltage security. Increased loading and exploitation of power transmission networks appear to have created a special voltage security problem, namely voltage stability. Traditional voltage profile criteria are not sufficient for electric power systems concerning the voltage stability problem[29][103]. With this in mind, it is quite natural to take voltage stability constraints into account in reactive power procurement optimization. There is an acute need for research work in the areas of voltage security and reactive power support. Reactive power plays an important role in supporting real power transfers and maintaining proper voltage profiles. This support becomes especially important when an increasing number of transactions are using a transmission system and when the voltage problems cause a bottleneck discouraging additional power transfers. As electric utilities attempt to maximize the uses of their transmission system capacities to transfer real power, voltage collapse can become a limiting factor [29]. In order to transport higher real power and improve voltage stability the design of optimal reactive power support to prevent voltage collapse is important. Some papers have been published on this topic in recent years. The work presented in [61][122] used two different methods, namely fuzzy linear programming and modal analysis, to solve optimal reactive power planning problem. The objective of reactive power support in both papers is to maximize the voltage stability margin. There are also publications addressing reactive power support with the objective of minimizing transmission losses [65][71][86]. These objectives are more or less focused on the technical aspect of reactive power support. To the best of our knowledge, no research publications are available on optimal procurement of reactive power support for maintaining voltage security, and this motivates our effort to investigate this topic in this thesis.

In summary, the following research topics associated with reactive power will be reported:

1) A new practical market approach for managing reactive power support from reactive power supplying facilities will be developed.
2) Pricing and cost allocations of reactive power support services will be examined.
3) Optimal procurement with reactive power support with voltage stability constraints will be investigated.

Research findings in this part are detailed in Chapters 4-7.

1.4 Outline of the Thesis

The remaining chapters of the thesis are organized as follows:

Chapter 2: A systematic approach for transient security enhancement under electricity market environment is developed. The application of the corrected hybrid method in transient security enhancement for single potential unstable contingency is presented. The methodology also responds to price since it is important in the deregulated environment. The objective is to eliminate potential transient insecurity under contingencies in commercially oriented power markets.

Chapter 3: A generalized generation dispatch method is developed for transient security enhancement in competitive deregulated power systems with multiple contingencies taken into account. A *global index* (GI) is first developed to compare the effects of different control schemes on transient stability enhancement. Then, a method of classifying critical and non-critical generator groups corresponding to different candidate contingencies is combined with a two-objective (mini-max) optimization formulation to develop the ‘best possible’ solution to this problem.

Chapter 4: A centralized reactive power management scheme is presented. Two problems are addressed: the procurement of reactive power suppliers and the settlement of the costs incurred, i.e., how to compensate suppliers and charge end users. Optimal reactive power dispatch is obtained with the objective of minimizing reactive power support cost. Then, a pricing structure including compensation for reactive power sources and charges on reactive power consumers is established with both technical feasibility and economic equitability taken into account.

Chapter 5: The reactive power pricing problem is investigated and expressed as a joint cost allocation problem. The costs incurred for reactive power support are fully allocated to participants in an equitable and transparent manner. The reactive power support cost of an individual generator is measured by its opportunity cost, which is evaluated by its profit loss in the active power market. The opportunity cost is precisely determined through the possible rescheduling by the ISO. Cost allocation factors for active loads and reactive loads are then calculated with the application of the *Aumann-Shapley* (A-S) method from game theory.

Chapter 6: An alternative way for the cost allocation problem of reactive power support is investigated. The problem examined in this chapter is basically similar to that described in Chapter 5, but is handled from a different perspective. A different mathematical model representing a different reactive power procurement scheme is employed in this chapter. Surely, the cost allocation problem will have different characteristics under different reactive power procurement schemes. Reactive power OPF is used for the procurement and dispatching of reactive power services. The optimal cost of reactive power is obtained by solving two decoupled sub-problems of active and reactive power optimizations. The A-S method is employed with some novel implementation techniques for the specific applications. A mathematical model of the optimization of reactive power and a description of the reactive power cost allocation problem for pool markets is first illustrated. Then, the discussion is extended to a model when pool and bilateral transactions coexist.

Chapter 7: A systematic method, relying on the basic concepts of opportunity cost and reactive compensator remuneration, is presented to optimize reactive power support in an electricity market environment with voltage stability requirements taken into account. Cost analysis and voltage stability analysis are integrated using an optimal power flow formulation.

Chapter 8: The main contributions of this PhD thesis and some directions for future research work related to security-constrained dispatch and reactive power management in the electricity market environment are concluded.

2 OPTIMAL GENERATION RESCHEDULING FOR TRANSIENT SECURITY ENHANCEMENT UNDER SINGLE CONTINGENCY

2.1 Introduction

In the electricity market environment, it is required to schedule generators based on bids from generation companies. The ideal (unconstrained) schedule without considering operating limits such as transmission capacity constraints and security constraints (contingencies) is not always feasible due to system security requirement. To maintain the secure operation of power systems, static and dynamic security must be taken into account. In this chapter, the dynamic security enhancement under the electricity market environment will be investigated.

Dynamic security assessment is the evaluation of the ability of the system to withstand specified contingencies by surviving the subsequent transient events to arrive at an acceptable steady-state operating condition. When potential instability consequence to a sufficiently credible contingency is detected, some preventive action has to be taken by system controllers.

The dynamic security constrained dispatch of an electric power network is a difficult task facing an ISO mandated to provide equitable and fair transmission services in an open-market environment. In a vertically organized monopoly system the authority of the system control center in respect of operational matters is unambiguous and issues relating to the individual interests of separate business entities do not arise. However, in a deregulated and unbundled electricity supply industry where generation, transmission and distribution are separated entities in terms of ownership and management, generation dispatch is a more complicated task, particularly so when dynamic security concerns have to be taken into account, since equity among generation companies has to be considered in addition to the system security. In other words, a system operating state can be modified in many different ways, and the operator must choose the action which will not only ensure system stability, but will also achieve commercial equitability in an open access environment.

This chapter focuses on transient security enhancement. As mentioned in *Chapter 1*, the hybrid method [87] for transient stability assessment is capable of incorporating detailed generator and other component representations and offers a stability index TEM based on traditional TEF [52][54]. Unfortunately, however, it has been observed that the variation of TEM computed by the hybrid method often exhibits erratic non-linearity around the critical value when plotted against some key system operating parameters. This limits the value of the method as a control tool for stability enhancement, since the changes of critical generator output or interface power flow predicted as necessary for stabilization, will be unreliable. A new index called *the corrected TEM* (CTEM) has been developed in the corrected hybrid method. This index based on the new definition of energy function, referred as *corrected TEF* (CTEF) has a linear relationship with certain parameters such as fault clearing time and generation rescheduling (shift of power from one generator to another). This advantage makes the corrected hybrid method suitable for devising control schemes for transient security enhancement.

When transient insecurity is detected, the ISO has to take some actions like generation rescheduling and even load curtailment. As already mentioned before, in an open access market environment commercial implications beside technical feasibility have to be considered when generators are required to rescheduled for purpose of security enhancement. Indeed, much research work has been carried out on system operation with transient security taken into account for pre-deregulation systems, for example [20][53][60][76][79][82][90][129]. However, less attention has been received for transient security constrained system operation in the market environment. To the best of my knowledge, only some preliminary research work [38][84][85][112][113] has been done in this area.

Given this background, a systematic research work is carried out for transient security enhancement under electricity market environment. Basic concepts of the corrected hybrid method, especially the calculation procedure and feature of CTEM, will firstly be presented. Then, its application on transient security enhancement for single potential unstable contingency is presented. Specifically, pool type power dispatch and bilateral contract transactions are both taken into account. A method is developed for rescheduling, based on the sensitivity of the corrected transient energy margin with respect to power shift between generators and sensitivity of the margin to transaction curtailment. The methodology also responds to price since these are important in the new deregulated environment. The objective is to eliminate potential transient insecurity under contingencies in commercially oriented power markets, and this is the so-called transient security enhancement. In this chapter, the research work is limited to the transient security enhancement under single contingency, while the problem under multiple contingencies will be examined in the next chapter.

2.2 Corrected Hybrid Method

2.2.1 System model

The generator equations of motion with respect to *the center of inertia* (COI) for an *n*-generator power system are generally denoted by:

$$\begin{gathered} M_i\dot{\tilde{\omega}}_i = P_{mi} - P_{ei} - \frac{M_i}{M_T}\sum_{i=1}^{n}(P_{mi} - P_{ei}) \equiv f(\cdot) \\ \dot{\theta}_i = \tilde{\omega}_i, \quad i = 1,2,\ldots,n \end{gathered} \tag{2-1}$$

where:

M_i : inertia constant of machine *i*,

$M_T = M_1 + M_2 + \cdots + M_n$,

P_{mi} : Mechanical power input of machine *i*,

P_{ei} : Electrical power output of machine *i*.

The expressions for evaluating P_{ei} are different for different system models and detailed equations for computing both P_{mi} and P_{ei}, for various system representations, can be found in well-known reference texts such as [54][73].

The TEF of a multi-machine power system modeled by (2-1) is defined by:

$$V = V_{KE} + V_{PE} = \frac{1}{2}\sum_{i=1}^{n} M_i\tilde{\omega}_i^2 - \sum_{i=1}^{n}\int_{\theta_i^{SP}}^{\theta_i} f_i^{P}(\cdot)d\theta_i \tag{2-2}$$

Where V_{KE} and V_{PE} represent the *transient kinetic energy* (TKE) and *transient potential energy* (TPE) functions, respectively; θ^{sp} denotes the angle vector of the *stable* *equilibrium point* (SEP) of the post-fault power system; the superscript *p* on $f_i^p(\cdot)$ emphasizes that the function refers to the post-fault system. The integral for V_{PE} is path dependent for a power network model which incorporates transmission losses.

It has been shown that not all of the TKE is responsible for system first swing separation and the TEM based on the traditional TEF defined by equation (2-2), used in the traditional hybrid approach, is not a proper estimate of the kinetic energy responsible for the separation of the "critical" machines from the rest of the system. Therefore, a correction, which excludes from consideration that portion of the kinetic energy which does not contribute to system instability, is required. Hence, the more useful concepts of *corrected transient kinetic energy* (CTKE) and *corrected transient potential energy* (CTPE), given below, have been derived.

From equation (2-1) the following can be obtained:

$$M_{eq}\dot{\omega}_{AB} = \frac{M_{eq}}{M_A}\sum_{i=1}^{n_A}(P_{mi}-P_{ei}) - \frac{M_{eq}}{M_B}\sum_{i=1}^{n_B}(P_{mi}-P_{ei}) \equiv \hat{P}_{AB} \tag{2-3}$$

where:

$$M_{eq} = M_A M_B / (M_A + M_B) \ ,$$

$$\omega_{AB} = \omega_A - \omega_B \ ,$$

$$\omega_A = \sum_{i=1}^{n_A} M_i \tilde{\omega}_i / M_A \ ,$$

$$\omega_B = \sum_{i=1}^{n_B} M_i \tilde{\omega}_i / M_B \ ,$$

$$M_A = \sum_{i=1}^{n_A} M_i \ ,$$

$$M_B = \sum_{i=1}^{n_B} M_i \,,$$

n_A and n_B denote the numbers of critical machines and rest (non-critical) machines respectively. CTKE(V_{KE}^{CO}), CTPE(V_{PE}^{CO}) and CTEF(V^{CO}) are defined in equation (2-4), equation (2-5) and equation (2-6) respectively.

$$V_{KE}^{CO} = \frac{1}{2} M_{eq} \omega_{AB}^2 \tag{2-4}$$

$$V_{PE}^{CO} = -\int_{\alpha_{AB}^{sep}}^{\alpha_{AB}} \hat{P}_{AB} d\alpha_{AB} \tag{2-5}$$

$$V^{CO} = V_{KE}^{CO} + V_{PE}^{CO} \tag{2-6}$$

In equation (2-5), $\alpha_{AB} = \alpha_A - \alpha_B$, where $\alpha_A = \sum_{i=1}^{n_A} \theta_i M_i / M_A$ and $\alpha_B = \sum_{i=1}^{n_B} \theta_i M_i / M_B$ are the COI angles of the two generator groups. It is obvious that $\dot{\alpha}_{AB} = \omega_{AB}$. Like the integral for V_{PE}, the integral for V_{PE}^{CO} is also path dependent for a power network model which includes transmission losses.

The definition of CTEF relies on the separation of the system machines into "critical" and "non-critical" ones. Moreover, this is a prerequisite of the construction for *corrected potential energy boundary surface* (CPEBS) and CTEM. CPEBS is illustrated in Figure 2-1 and will be explained later. Hence, proper identification of these two groups of machines is the first step in the corrected hybrid method. The identification problem itself is not the topic of this chapter since it is an important topic and has been discussed in the literature. The method based on an acceleration criterion presented in [43][128] to separate the system into critical and non-critical machines is employed in this thesis.

It has been verified by many researchers that along a post fault trajectory, such as TR_a and TR_c of Figure 2-1, modeled by equation (2-1), the CTEF is conservative. This means that any loss or gain of CTKE is converted into CTPE in equal but opposite measure as required by the principle of conservation. From this property it follows that there are two important alternative trajectory histories to consider. Case 1(first swing stable, TR_a): all the CTKE is converted to CTPE when the former monotonically reaches its zero minimum. Case 2(first swing unstable, TR_c): CTKE is partially converted to CTPE up to the point where the former monotonically reaches a non-zero positive minimum. Furthermore, for the latter (unstable case), the CTPE will monotonically reach a maximum (when the CTKE monotonically reaches this non-zero minimum), at a point where $\hat{P}_{AB} = 0$ and is passing from negative to positive along the trajectory. In addition, it can be observed that for a sustained fault trajectory (TR_o) leading to loss of stability, CTPE will again monotonically increase and reach a maximum. This maximum point, if projected on to the post-fault system state space corresponds again to a point where $\hat{P}_{AB} = 0$.

These observations can be used to construct a surface in the generator angle space in the COI frame called CPEBS which is defined by the equation of $\hat{P}_{AB} = 0$ in the post-fault system configuration and state space. This boundary surface is of great significance for transient stability and energy margin analysis of a contingency leading to this post fault configuration.

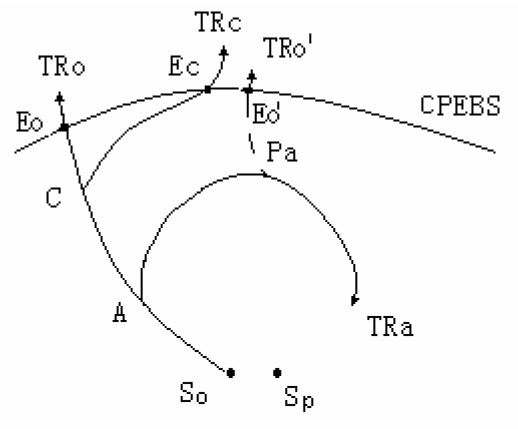

Figure 2-1. Illustration of CTEM assessment associated with time domain simulation

2.2.2 CTEM assessment

CTEM assessment based on the CPEBS is outlined here. Figure 2-1 illustrates the principle of CTEM evaluation associated with time domain simulation. Here, the line at the top represents the CPEBS. S_o and S_p are the stable equilibrium points of the pre-fault and post-fault systems, respectively. TR_o is the projection of the sustained fault-on trajectory on the post fault system angle space in the COI frame. This trajectory starts at S_o and crosses the CPEBS at exit point E_o. TR_a and TR_c illustrate the projections of the post-fault trajectories corresponding to stable and unstable cases, respectively. P_a is the CTPE peak point at which trajectory TR_a begins to swing back and at which point $\omega_{AB} = 0$. E_c is the exit point at which trajectory TR_c crosses the CPEBS. Furthermore, $\hat{P}_{AB}$ is zero at this point. At E_c the value of ω_{AB} reaches its first non-zero positive minimum. The projected trajectory TR_o' refers to the case when a permanent fault is re-inserted at P_a driving the system to instability at the exit point E_o' of the CPEBS.

The definition of CTEM depends on the post-fault trajectory simulation. For the unstable case, it is defined as opposite value of the CTKE at the exit point (E_c in Figure 2-1) of the post-fault trajectory on the CPEBS. For the stable case the CTEM is defined as the CTPE increment from the CTPE peak point (P_a) to the exit point E_o' on the CPEBS of the re-inserted permanent fault trajectory. In physical terms the stable CTEM gives a measure of how much more CTKE the post-fault system can withstand (convert to CTPE) before going unstable. This approach to CTEM evaluation is summarized as follows.

1) Determine the system state at fault clearing and then continue time simulation of the post-fault power system, keeping track of ω_{AB} along the simulation trajectory. If ω_{AB} passes through a positive minimum value, go to step 2). If ω_{AB} changes its value from positive to negative, go to step 3).

2) The case of first swing instability: The CTEM is evaluated by $CTEM = -\frac{1}{2}M_{eq}\omega_c^2$, where ω_c is the value of ω_{AB} at CPEBS crossing E_c.

3) The case when the first swing is stable: Perform a "re-inserted fault-on" simulation commencing at the CTPE peak P_a, then locate the exit point of this trajectory on the CPEBS, that is point E_o'. Denote the system state at P_a by T_a and the state at E_o' by T_b, then the CTEM is defined by the following expression:

$$CTEM = -\int_{\alpha(T_a)}^{\alpha(T_b)} \hat{P}_{AB} d\alpha \tag{2-7}$$

where α stands for α_{AB} defined after equation (2-5).

From the discussion surrounding Figure 2-1 we can conclude that for a given fault: 1) CTEM is positive if and only if the system is stable 2) CTEM is negative if and only if the system is transient unstable 3) when CTEM is zero we say that the system is critical.

2.2.3 Sensitivity analysis

CTEM is a quantitative index of system transient stability and attempts have been made to derive stability enhancement procedures using its sensitivity to changes in system parameters. Analytical expressions for the sensitivity of the energy margin to system parameters are given in reference [54], but they are useable only for the classical model. Considerable previous work by associated researchers in our group has established through numerous simulations over a wide range of operating conditions that the CTEM bears a linear relationship to several operating parameters which is sufficient for control purpose. Their studies have been reported in references [43][45][46][47]. We have reconfirmed their findings through simulation studies on other system models. These control parameters include fault clearing time and generation rescheduling (shift of power from one generator to another) and curtailment of a bilateral transaction (power input and load reduction, in equal magnitude). Sample results of the investigation of the linearity range can be found in *Section 2.4.2*. This linearity finding can be expressed as follows:

$$\Delta CTEM = \lambda_s . \Delta C_s \tag{2-8}$$

where $\Delta CTEM$ is change in CTEM, ΔC_s is change in an operating parameter and λ_s is sensitivity of CTEM to the parameter.

When CTEM bears a linear relationship to ΔC_s the value of λ_s is a constant and simulation results show that is true for ΔC_s in fair range. Obviously, a positive value of λ_s benefits transient stability while negative λ_s is harmful. If the transient margin is $CTEM^A$ in state A then the value in state B is $CTEM^B = CTEM^A + \lambda_{A\to B} . \Delta C_{A\to B}$. If the initial $CTEM^A < 0$, and the modified state $CTEM^B$ is set to zero, then $\Delta C_{A \to B}$ is the operating parameter change required to stabilize the system.

2.3 Transient Security Enhancement with Single Contingency

Power system stability can be enhanced at two distinct levels of control. Level one is device-based and includes excitation, governor, HVDC, SVC, and FACTS control. Level two is operation-based and is conducted in the system control centre and includes such measures as power flow control. The latter includes both preventive action before a possible contingency and corrective control as an after the fact action. In the case of transient instability there is not much of a corrective nature that can be done under practical operating conditions although there are some fast acting corrective control measures, such as dynamic braking, turbine fast valving and high-speed excitation systems in use. The topic of this chapter, however, is preventive control in pool and bilateral-contract mixed systems.

2.3.1 Pool model

A pool selling or buying transaction is a price-quantity-based offer to the pool by a *generation company* (GENCO) or a buy offer from a *distribution company* (DISCO). When a transient stability hazard is detected the ISO will have to intervene. The proposed action must be feasible, technically sound and commercially fair to all market participants. The problem can be formulated in the following way.

$$\text{Min} \sum \rho_{Gi} \left| \Delta P_{Gi} \right| \tag{2-9}$$

subject to:

$$\sum_{m\in A,n\in B} \lambda_{m\to n} G_{m\to n} \geq \left| CTEM^{0} \right|$$
$$P_{Gi}^{\min} \leq P_{Gi} + \Delta P_{Gi} \leq P_{Gi}^{\max}$$
$$\sum \Delta P_{Gi} = 0$$

where ρ_{Gi} and ΔP_{Gi} are the per unit bid price (more fully discussed in *Section 2.3.4*) and the power output change of the *i*-th generator respectively; $CTEM^{0}$ is the energy margin value, which will be negative when the system is transient unstable; A and B are the critical generator group and the non-critical group, respectively; $m \in A$ and $n \in B$ denote the *m*-th and *n*-th generators belong to critical group and non-critical group respectively; $G_{m\to n}$ is the generation shift for *m*-th to the *n*-th generator and $\lambda_{m\to n}$ is the sensitivity of CTEM to $G_{m\to n}$; $P_{Gi}^{\min}$, $P_{Gi}^{\max}$ are *i*-th generator power limits. The first constraint imposes the condition that after generation rescheduling the transient stability index should be positive and the second ensures that generator power limits are not violated. The last constraint ensures invariance of total generation, i.e. transmission loss is neglected.

Discussions:

a) Only generation shift from critical to non-critical units can improve system transient stability, hence $G_{m\to n}$ is always positive in the cases of interest.

b) When generation shift is within the linearity limits of sensitivity and the per unit generation bid price is taken as constant, we have a simple linear programming problem.

c) In case (b), the optimal ΔP_G values are a linear combination of $G_{m\to n}$ values at solution, that is, obviously, $\Delta P_{Gn} = -\sum_{n\in B} G_{m\to n}$ and $\Delta P_{Gm} = \sum_{m\in A} G_{m\to n}$.

d) The objective function is, in the view of ISO, based on the assumption that the generation schedule prior to rescheduling is the most economic. The consequence of rescheduling (away from this economic dispatch state) is an increase of cost.

2.3.2 Bilateral model

A bilateral transaction is a contract entered into directly between a GENCO-DISCO pair. The conceptual model of a bilateral contract is that sellers and buyers enter into agreements where the quantities and trade prices are at the discretion of these parties and not a matter for the ISO. This chapter does not, for simplicity of presentation, extend the discussion to the case where a GENCO or a DISCO contracts with several partners, but the extension is quite easy to formulate. Bilateral contracts are brought to the attention of the ISO with a request that transmission facilities for the relevant amount of power be provided. If there are no technical infeasibilities the ISO simply dispatches all requested transactions and charges a use of system charge for the service. Only when security is threatened does the ISO intervene to make decisions on curtailment. The methodology examined in this chapter is when curtailment follows a user-pay philosophy were “willingness-to-pay not to be curtailed” (w) is an indicator of the importance that parties to a transaction place on unfettered dispatch. The problem is illustrated as follows:

$$\text{Min } \sum w_k \Delta T_k \tag{2-10}$$

subject to:

$$\sum \lambda_k \Delta T_k \geq \left| CTEM^0 \right|$$
$$P_{Gi}^{\min} \leq P_{Gi} + \Delta P_{Gi} \leq P_{Gi}^{\max}$$

where w_k is the "willingness-to-pay" price premium to avoid transaction curtailment; ΔT_k is the k-th bilateral transaction power change, λ_k the correspond sensitivity of CTEM to this power change; $CTEM^0$, $P_{Gi}^{\max}$, $P_{Gi}^{\min}$, P_{Gi}, ΔP_{Gi} and the meaning of the constraints are the same as in (2-9).

Discussions:

a) To enhance stability the output of a critical bilateral generator has to be reduced. In the simple bilateral model, therefore a corresponding load reduction is necessary.

b) When the bilateral transaction curtailment is within the linearity limits of λ_k the problem reduces to a simple linear optimization problem.

2.3.3 Integrated transaction model

In real world open access transmission, as it is now evolving, pool and bilateral transactions coexist. The issue for integrating them into a single rescheduling strategy when the existing transaction schedule is liable to cause system transient security problems is discussed in this section. The following assumptions are made: a) all loads remain unchanged (that is dispatched in full); b) generation rescheduling is executed from critical pool generators and critical bilateral generators to non-critical pool generators only, hence c) transaction rescheduling between one bilateral contract and another is not considered. Generation shift from a critical bilateral generator to a non-critical pool generator, therefore, means that some bilateral loads may have to buy power from the pool after rescheduling because their regular suppliers have been curtailed. We define $\bar{w}_j$ as the *j*-th bilateral generator's willingness to pay to avoid generation change. This value can be derived from the set of bilateral transaction willingness-to-pay factors that this generator enters into and may be written,

$$\bar{w}_j = f_j(w_{1j}, \cdots, w_{Kj}) \tag{2-11}$$

where $w_{1j}, \cdots, w_{Kj}$ are willingness-to-pay factors of individual bilateral transactions entered into by the *j*-th bilateral generator and $f_j(\ )$ is a function of $w_{1j}, \cdots, w_{Kj}$.

The optimal curtailment problem is then formulated as,

$$\text{Min} \sum_{m \in Pool} \rho_m \left|\Delta P_m\right| + \sum_{n \in Bilateral} \bar{w}_n \left|\Delta P_n\right| \tag{2-12}$$

subject to:

$$\begin{aligned} &\sum \lambda_d S_d \geq \left|CTEM^0\right| \\ &P_{Gi}^{\min} \leq P_{Gi} + \Delta P_{Gi} \leq P_{Gi}^{\max} \\ &\sum \Delta P_{Gi} = 0 \end{aligned}$$

where S_d is the generation shift which includes shift from both critical pool and critical bilateral generators to non-critical pool generators; λ_d is the corresponding set of sensitivities of CTEM to these shifts; $CTEM^0$, P_{Gi}^{max}, P_{Gi}^{min}, P_{Gi}, ΔP_{Gi} are the same as in (2-9).

Discussions:

a) If the critical and relevant non-critical generators all belong to the pool, the problem is the same as *Section 2.3.1*.

b) Since $\Delta P_m, \Delta P_n$ can be expressed as linear combinations of S_d and if λ_d, ρ_m, $\bar{w}_n$ are constant, the problem is linear.

c) Spreading any reduction in the permitted dispatch of a bilateral generator among the loads contracted with this generator can be arranged as follows.

$$\begin{aligned} &\eta_{j1}\Delta T_{j1} = \cdots = \eta_{jK}\Delta T_{jK} \\ &\sum_{k=1\cdots K} \Delta T_{jk} = \Delta P_j \end{aligned} \tag{2-13}$$

where $\eta_{jk} = w_{jk} \Big/ \sum_{k=1\cdots K} w_{jk}$, ΔP_j is the reduction of the *j*-th bilateral generator dispatch and ΔT_{jk} the change in the individual bilateral transactions entered into by this generator. It is easy to see from (2-12) that curtailment is inversely related to transaction willingness-to-pay.

2.3.4 Transient security auction

The previous discussion points the way to an auction mechanism that can become a practical way to deal with transient security concerns in a power market. The transient security auction concept will be illustrated using the simplest case, equation (2-9) of *Section 2.3.1*, but is easily extended to the bilateral and integrated models of *Sections 2.3.2* and *2.3.3*.

Rewrite (2-9) in the simpler form:

$$\text{Min} \sum \rho_k \cdot S_k \tag{2-14}$$

subject to:

$$\sum \lambda_k \cdot S_k \geq C$$

Where S_k is the amount of output power to be shifted from one generator to another, and ρ_k is the price at which a pair of generators have bid to implement power shifting between them. The bidders must be a pair of generators, one critical and the other non-critical. The value λ_k is a measure of ability of the shift to contribute to the satisfaction of a useful outcome. The constant *C* is the gross amount of this useful outcome required by the purchaser (in this case the ISO). If we define $x_k = \lambda_k \cdot S_k$, the problem becomes:

$$\text{Min} \sum \alpha_k \cdot x_k \tag{2-15}$$

subject to:

$$\sum x_k \geq C$$

Where $\alpha_k = \rho_k \lambda_k^{-1}$ is the sensitivity weighted bid price. Now if *k* is arranged in decreasing magnitude of α_k, the process is one of “purchasing” *x*-commodity 1 at weighted price α_1, up to the limit available, *x*-commodity 2 at weighted price α_2 up to the limit available, and so on until the total amount purchased is *C*. This is an auction mechanism, which can be conducted by the ISO at short intervals and ρ_k are the price bid by generator pairs who wish to participate in the auction. The ISO then weights the bid price by the sensitivity λ_k, which is computed by the ISO’s monitoring and energy management software, solves the simple optimization problem, and allocates the results to generator pairs. One generator may be involved in several shift pairs and the total change of output incurred by a generator should not exceed its power limit. Overall system demand curtailment is a further worse case to which this formulation can be extended if no feasible solution can be found to (2-9).

The need for critical and non-critical generators to bid into the auction as a pair can be avoided and individual generator bids accepted if the following procedure is adopted. A non-critical reference generator, says *R*, is identified by the ISO. Sensitivities λ_{n-R} of all critical generators when they reduce their individual power, assuming such power is taken by *R* and the sensitivities λ_{R-m} of all non-critical generators when they increase their individual power assuming such power is taken from *R* can be calculated by the methods described previously. Now, the ISO's optimization procedure can be easily reformatted while including the condition of zero net power change at *R*. The optimization process will now deliver a lower value of the objective function because of the relaxation of the pair wise constraint. The elaboration of the auction procedure to the bilateral and integrated cases will be along the same lines.

2.4 Case Studies

2.4.1 Optimization results

These procedures for improving transient security have been tested using New England 39-bus system data [3]. The system has 10 generators, 39 buses and 46 tie-lines. Bus 31 has been chosen as the slack bus designated to make good transmission losses and is not involved in generation rescheduling. The generators at buses 32 and 38 are bilateral generators while all others belong to the pool – the term "bilateral generator" refers to the seller in a bilateral contract. Loads at buses 3 and 16 have individual a bilateral contract with the generator at bus 32 and similarly the loads at buses 23 and 29 buy power from the generator at bus 38. All other loads buy power from the pool. For simplicity the cases of generators or loads which enter into bilateral contracts as well as participate in pool purchases are not included in this case study. The initial real power outputs of pool generators and the corresponding bid prices are given in Table 2-1. Table 2-2 gives bilateral transactions and associated “willingness-to-pay not to be curtailed” factors.

Table 2-1. Pool generator optimal dispatch and price data

Bus-Name	Output (MW)	Bid Price ($/MWh)
30	250	6
33	632	9
34	508	9
35	650	6
36	560	4
37	540	15
39	1000	11

Table 2-2. Bilateral contracts and “willingness” data

Bilateral Contract	Transfer (MW)	Willingness w ($/MWh)
B1 (32-3)	322	7
B2 (32-16)	328	9
B3 (38-23)	310	18
B4 (38-29)	520	14

Table 2-3. Sensitivity factor of generation shift

Generation Shift (100MW)	Sensitivity Factor
G32 to G30	.375
G33 to G30	.662
G34 to G30	.678
G35 to G30	.570
G36 to G30	.675
G37 to G30	2.48
G38 to G30	2.45
G32 to G39	.510
G33 to G39	.754
G34 to G39	.811
G35 to G39	.780
G36 to G39	.753
G37 to G39	2.91
G38 to G39	3.11

Table 2-4. Sensitivity factor of bilateral transaction curtailment

Bilateral Transaction Curtailment (100MW)	B1	B2	B3	B4
Sensitivity Factor	0.379	0.047	1.540	1.308

Transient security is examined for a three-phase short circuit at bus 26 cleared by tripping line 25-26 after 0.25s. Simulation results show that the system is transient unstable and that the transient energy margin is –1.449. The generators at buses 30 and 39 are non-critical and all the others are critical. The sensitivity factors of generation shift and bilateral transaction curtailment to transient energy margin are given in Tables 2-3 and 2-4. These sensitivities have been obtained by repeating the transient stability simulation runs after making a power shift between the relevant generators, or after curtailing bilateral contracts. Three different schemes to improve system transient stability are now analysed.

Case 1: Shift generation among pool generators but no change in bilateral transactions.

Table 2-5. Pool generator output data after rescheduling

Bus-Name	30	33	34	35	36	37	39
Output (MW)	**300**	632	508	650	560	**482**	**1008**
Cost ($/h)	1258						

It can be observed from Table 2-5 that the critical generator at bus 37 has transferred 50MW to the generator at bus 30 and 8MW to the generator at bus 39. The permitted linearity limit for the most advantageous bus 37 to bus 30 transfer was 50MW.

Case 2: Bilateral transaction curtailment only; no rescheduling of pool generation.

Table 2-6. Bilateral transaction curtailment

Bilateral Transaction	B1	B2	B3	B4
Curtailment (MW)	11.5	0	50	50
Cost ($/h)	1680.5			

Notwithstanding their greater willingness to pay to avoid transaction curtailment seen in Table 2-2, B3 and B4 have borne the brunt of cuts because of their much higher sensitivity coefficients tabulated in Table 2-4. Both of these were curtailed to the linearity limit before the final cuts were imposed on B1.

Case 3: Bilateral loads threatened with curtailment allowed to buy power from the pool

Table 2-7. Generator power and bilateral transaction curtailment

<table>
<tr><td>Bus-Name</td><td>Output (MW)</td><td rowspan="2">Bilateral Transaction</td><td rowspan="2">Curtailment (MW)</td></tr>
<tr><td>30</td><td>300</td></tr>
<tr><td>32</td><td>650</td><td rowspan="2">B1</td><td rowspan="2">0.0</td></tr>
<tr><td>33</td><td>632</td></tr>
<tr><td>34</td><td>508</td><td rowspan="2">B2</td><td rowspan="2">0.0</td></tr>
<tr><td>35</td><td>650</td></tr>
<tr><td>36</td><td>560</td><td rowspan="2">B3</td><td rowspan="2">3.06</td></tr>
<tr><td>37</td><td>490</td></tr>
<tr><td>38</td><td>823</td><td rowspan="2">B4</td><td rowspan="2">3.94</td></tr>
<tr><td>39</td><td>1007</td></tr>
<tr><td colspan="2">Cost ($/h)</td><td colspan="2">1239</td></tr>
</table>

It can be observed from Table 2-7 that the critical pool generator at bus 37 shifts 50MW (linear shift limit) to the non-critical pool generator at bus 30. The critical bilateral generator at bus 38 shifts 7MW to the non-critical pool generator at bus 39. The latter means bilateral transactions relative to generator at bus 38 have to be cut and the relevant loads now buy power from the pool. Hence there is a curtailment 3.6MW and 3.4MW, respectively, of B3 and B4 although the loads themselves are not reduced because of the substitution of pool power.

Cost in case 3 is the lowest compared with cases 1 and 2. Obviously if a bilateral load is permitted to buy power from the pool, the mathematical solution space is expanded. Hence this turns out to be the best solution.

2.4.2 Investigation of linearity

The success of this method is dependent on the range of power rescheduling between critical and non-critical generators and curtailment of bilateral power exchanges, over which the change of the stability index remains linear. If this range is too small it would be necessary to implement the algorithm in smaller steps, which would not pose any significant computational difficulty, but the real concern is that, in that case, there would be a breakdown of the auction market mechanism. The success of the auction, conducted by the ISO during periods of transient insecurity concern, depends on not having to engage in a procedure requiring repeated iterations between calling for bids and decision-making. Ideally, it should be one-shot auction whose conclusion, that is the ISO's rescheduling decisions, remains valid for the remainder of the period of concern.

The range of linearity has been investigated for this example and has been shown to be quite wide. It has also been found that power shifting between generators has a wider range of linearity than curtailment of bilateral transactions. Some examples for a potentially unstable contingency are illustrated from Figure 2-2 to Figure 2-5. The vertical axis is the CTEM index and the horizontal axis gives the power shift corresponding to increasing CTEM values, are of practical interest. Figure 2-2 and Figure 2-3 show the effect of shifting power from critical generator 38 to non-critical generators 30 and 39, respectively, while Figure 2-4 and Figure 2-5 illustrate the curtailment of bilateral transactions B1 and B3, respectively.

These examples of linearity in power exchange in MW vs. CTEM are satisfactory in relation to the system size and the power supply magnitudes in the New England test system. For a given MW rescheduling in a non-stressed system, the larger the system is the better the linearity is.

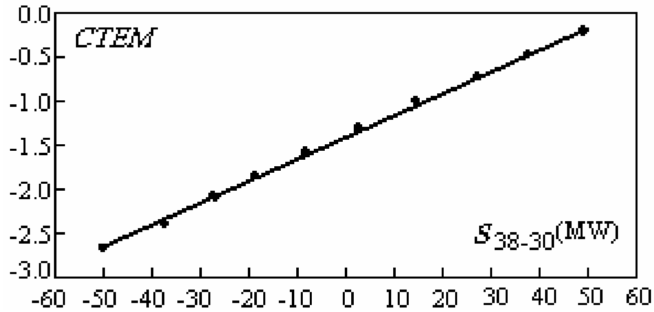

Figure 2-2. CTEM vs. power shift from G38 to G30

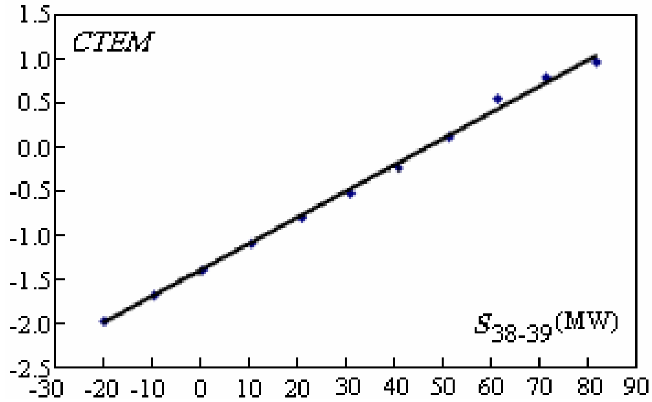

Figure 2-3. CTEM vs. power shift from G38 to G39

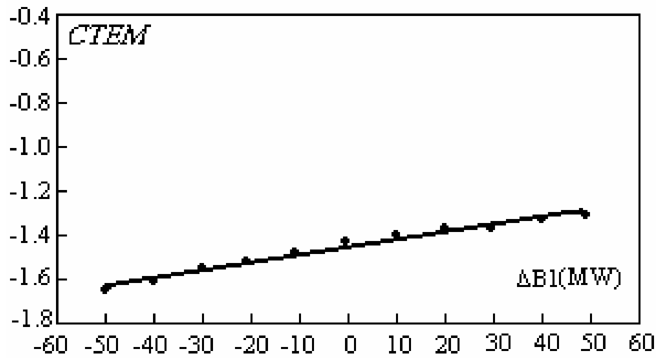

Figure 2-4. CTEM vs. bilateral contract (B1) curtailment

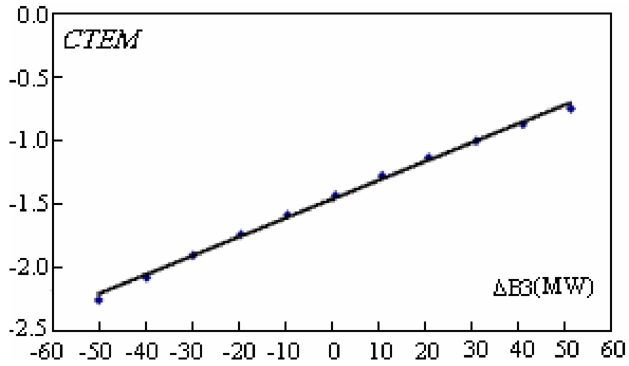

Figure 2-5. CTEM vs. bilateral contract (B3) curtailment

The last example in Figure 2-6 shows the sensitivity of curtailment if we had assumed that a bilateral contract existed between the generator at bus 37 and the load at bus 26. In this case the linear range is smaller, only 20MW, and this smaller number would have to be inserted as the range limit, for this variable, in the linear program inequality constraint list.

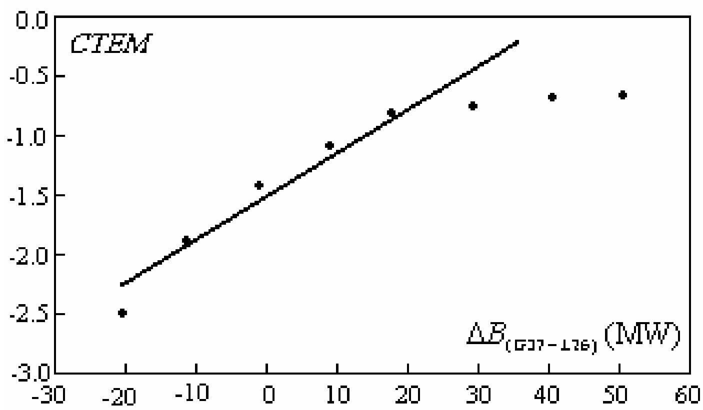

Figure 2-6. CTEM vs. assuming bilateral contract (G37-L26) curtailment

2.4.3 Computer time

The entire procedure consisting of estimating and broadcasting sensitivity indices, calling for price bids (transient stability auction) and allocating new schedules (finding the optimal solution) needs to be completed in a few minutes if the method is to be acceptable for real time application. It has been found that one complete fault clearing simulation and CTEM computation requires about 2s on a fast personal computer and about four complete simulations (about four points on the graphs of Figure 2-2 to Figure 2-5 for example) are required to determine the slope (sensitivity). Typically there may be 10 to 20 pairs of power exchange options or bilateral transaction curtailments to model in a practical case. Overall this comes out at a total of about one to three minutes to deal with any particular contingency under investigation.

The problem structure is extremely suitable for parallel computing application or even for processing on independent PCs. Different contingencies can be dealt with entirely independently. Even in the slope calculation, the computations in respect of each of the points in Figure 2-2 to Figure 2-5, for example, are independent of each other, and are suitable candidates for parallel processing. The results only need to be brought together for final slope estimation.

2.5 Summary

1) An optimal generation rescheduling approach for transient security enhancement under single contingency in an open access market environment is developed. The approach relies on a stability index, i.e. the so-called CTEM computed by the corrected hybrid method, which bears a linear relationship to certain system operating variable changes such as power exchanges between generators or bilateral contract curtailments.

2) Transient security enhancement for one potential unstable contingency can be formulated as a simple linear optimization problem with the objective of minimum

deviation from original market-based operating point. It is easy to find an optimal generation rescheduling scheme in this case.

3) Based on the research work in this chapter, it is possible to design a price driven auction mechanism, which will optimize generation rescheduling, and transaction curtailment for transient security enhancement in an electricity market environment. To some extent, the developed method actually represents a transient security auction mechanism.

4) The transient security enhancement for multiple contingencies in the electricity market environment will be investigated in the next chapter.

3 OPTIMAL GENERATION RESCHEDULING FOR TRANSIENT SECURITY ENHANCEMENT UNDER MULTIPLE CONTINGENCIES

3.1 Introduction

It is well acknowledged that the ongoing deregulation of the energy market needs to consider commercial implications when generators are re-dispatched to eliminate potential transient instability after a contingency to ensure transient security. A further complication is that different candidate contingencies may motivate different re-dispatch strategies because the critical generator group is different in each case, or the sensitivity of the stability margin to power exchanges between generators is different. Transient security enhancement in the electricity market environment has been deemed to be one of the most difficult research topics in the restructured power systems.

In *Chapter 2*, a methodological framework for transient security enhancement in the electricity market environment is developed, with the focus on the treatment of a single contingency. However, since there are many possible contingencies (candidates) in large-scale power systems, hence in making normal system dispatch it is very possible that a measure used to improve security for one contingency may adversely affect another, particularly for the transient security enhancement problem. Specifically the critical generator group may be different for different potential contingencies. This raises the more complex concern of trade-off between conflicting requirements and even the case where no rescheduling scheme can completely meet the requirements of all candidate contingencies. As a result, the method developed in *Chapter 2* cannot be readily extended to the case with multiple contingencies.

Given this background, it is the objective of this chapter to develop a generalized approach for addressing this important issue in competitive deregulated power systems, i.e., to present a generalized generation dispatch method for transient security enhancement with multiple contingencies taken into account. Specifically, a *global index* (GI) is first developed to compare the effects of different control schemes on transient stability enhancement. Then, a method for classifying critical and non-critical generator groups corresponding to different candidate contingencies is combined with a two-objective (mini-max) optimization formulation to develop the 'best possible' solution to this problem. Finally, illustrative examples of the multi-contingency case, when there are conflicting candidate contingencies to be considered, are studied.

3.2 Generation Rescheduling for Multi-Contingency

3.2.1 Basic concept

When only one contingency is involved, it is easy to find an optimal generation rescheduling solution, if it exists. This matter has been examined with sufficient details in *Chapter 2*. However it is difficult to find an operating point that is transient secure for several possible contingencies; sometimes such an operating point may not exist [90].

By shifting power from critical generators to non-critical generators we may enhance the system transient stability. However, the mode of system transient separation is different for different contingencies. Consequently a generator, which is classified as critical for one contingency, could be non-critical for another. This means that the same generation shift will be useful for some contingencies but may be harmful for others. In the remainder of this section only critical contingencies are considered. Let A_j stands for the critical generator set for the *j*-th contingency and B_j the non-critical generator set. If the inclusion set of all A_j ($\cap A_j$) is null, then there is no generation shift that is beneficial for all candidate contingencies. The same is true if $\cap B_j$ is null. Security enhancement is impossible in these cases in the sense that improving security for any contingency makes it worse for at least one other contingency. In this chapter, we assume the feasible generation shift domain, where a generation shift beneficial for all candidate critical contingencies is possible, is not null. However, this does not mean that there exists a generation rescheduling scheme making all potentially critical contingencies completely secure at the same time. Improvement or enhancement of security may be feasible, but complete security unreachable.

As a simple illustration, assume there are two potentially unstable faults F_1, F_2 in the system. Let the critical generator set for F_1 be A_1 and let B_1 be the non-critical generator set. Similarly, let A_2 and B_2 stand for the critical and non-critical generator sets of fault F_2. These sets are shown in Figure 3-1a and Figure 3-1b respectively .The inclusion set of A_1 and A_2 ($A= A_1 \cap A_2$) and the inclusion set of B_1 and B_2 ($B= B_1 \cap B_2$) are then shown in Figure 3-1c. Only generation rescheduling from region *A* to region *B* can improve stability for both faults F_1 and F_2. Now suppose *A* contains two generators *X* and *Y* and *B* contains only one generator *Z*. Then there are two available generation shift patterns;

one is power shift from *X* to *Z* ($G_{X\to Z}$) and another is from *Y* to *Z* ($G_{Y\to Z}$). Then, using equation (2-8) of *Chapter 2* the effect of the two generation shifts can be written as:

$$\Delta CTEM^1 = \lambda^1_{X\to Z}.G_{X\to Z} + \lambda^1_{Y\to Z}.G_{Y\to Z} \tag{3-1}$$

$$\Delta CTEM^2 = \lambda^2_{X\to Z}.G_{X\to Z} + \lambda^2_{Y\to Z}.G_{Y\to Z} \tag{3-2}$$

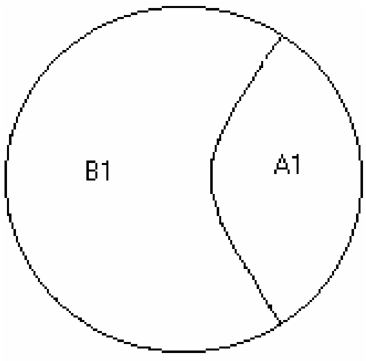

Figure 3-1a. A_1 and B_1 are critical and non-critical sets of fault F_1

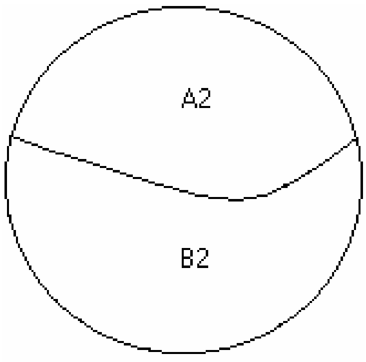

Figure 3-1b. A_2 and B_2 are critical and non-critical sets of fault F_2

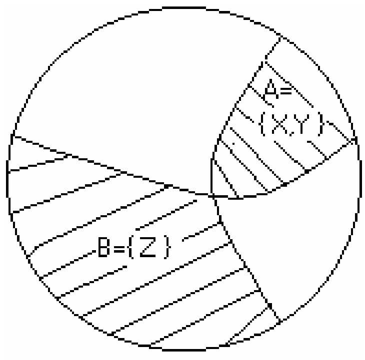

Figure 3-1c. Feasible generation shift domain

But, it should be noted that the sets A and B could, for some F_1, F_2, (or for some large set of contingencies F_1, F_2, F_3…), be empty, making mutual stability enhancement impossible.

Returning to the example, and noting that (3-1) and (3-2) are linear, let L1 and L2 in Figure 3-2 be the loci of generation to be shifted from *X* and *Y* to *Z* to just ensure transient security for faults F_1 and F_2 respectively. These loci are straight lines by virtue of the linearity properties. Transient stabilization implies $\Delta CTEM^1 = \left| CTEM_0^1 \right|$ and $\Delta CTEM^2 = \left| CTEM_0^2 \right|$ along L1 and L2 respectively. Now let line L3 represents the generator *Z* output limit (maximum power that *X* and *Y* together can transfer to *Z*). The domain enclosed by the two axes and L3 is the feasible domain of ($G_{X\to Z}$, $G_{Y\to Z}$). Then, when ($G_{X\to Z}$, $G_{Y\to Z}$)$\in D_1$ is true, contingency F_1 can be stabilized by generation rescheduling. Similarly, when ($G_{X\to Z}$, $G_{Y\to Z}$)$\in D_2$ is true, contingency F_2 can be stabilized by generation rescheduling. However, there is no inclusion domain for both F_1 and F_2 in the case illustrated in Figure 3-2, that is $D_1 \cap D_2$ be empty. Hence no generation rescheduling scheme will stabilize the system for both contingencies. These concepts can be easily extended to cases with lager numbers of generators and more than two critical contingencies.

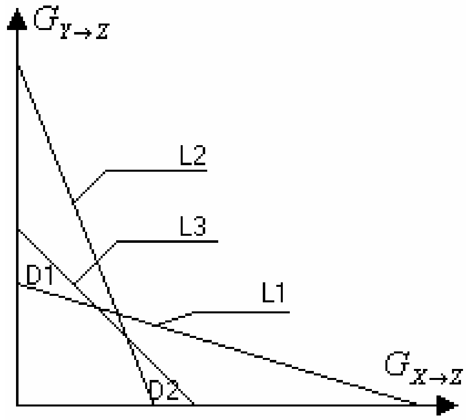

Figure 3-2. Illustration of effect of power shift on different contingency

3.2.2 Global index and its application to generation rescheduling

Improvement of *CTEM* denotes stability enhancement only for a particular fault but when there is more than one potentially unstable contingency it is necessary to develop a sounder index. It is impossible to compare the effect of different control schemes on stability enhancement without such an index. Furthermore, the index should be capable of dealing with the problem of trade-off among contingencies. It is especially useful for the case when no scheme can completely satisfy all the candidate contingencies simultaneously as illustrated in *Section 3.2.1*.

Define an energy margin change rate R^j for *j*-th fault as:

$$R^j = \Delta CTEM^j \Big/ \left| CTEM_0^j \right| \tag{3-3}$$

where $CTEM_0^j$ is the corrected transient energy margin of the initial state (before generation rescheduling) and "*j*" is an index over the set F of all potentially transient unstable contingencies. Comparing the energy margin change rate for different contingencies the effect of the various rescheduling strategies on different contingencies can be appreciated. For the purpose of trade-off among contingences, the global index should be able to reflect the severity of different contingencies. This can be achieved by using a weight coefficient (μ). The weight coefficient μ depends on many factors such as frequency of the contingency, duration of the outage and financial loss caused by the contingency. It has to be chosen by engineering judgment based on these concerns. Hence the global index of stability enhancement for a particular control scheme is developed as follows. Let,

$$GI = \sum_{j \in F} \mu^j \times R^j \tag{3-4}$$

From (2-8) and (3-3), (3-4) can be written as:

$$GI = \sum_{j \in F} \frac{\mu^j \times \sum\limits_{m \in A, n \in B} \lambda^j_{m \to n} G_{m \to n}}{\left| CTEM^j_0 \right|} = \sum_{m \in A, n \in B} C_{m \to n} G_{m \to n} \tag{3-5}$$

where:

$$C_{m \to n} = \sum_{j \in F} \frac{\mu^j \times \lambda^j_{m \to n}}{\left| CTEM^j_0 \right|}\,, \tag{3-6}$$

where A and B are the critical generator group and the non-critical group, respectively; $m \in A$ and $n \in B$ denote the m-th and n-th generators belong to critical group and non-critical group respectively; $G_{m \to n}$ is the generation shift for m-th to the n-th generator; $\lambda^j_{m \to n}$ is the sensitivity of $CTEM^j$ to $G_{m \to n}$ for the j-th contingency. Observe that equation (3-5) has a similar style to equation (2-8). We can call $C_{m \to n}$ the sensitivity of generation shift to the global index.

GI is an overall indicator of the role of the generation rescheduling scheme for stability enhancement. Furthermore, by adjusting weight coefficient μ^j , a trade-off among contingencies can be examined.

The higher the value of *GI*, the better is the scheme from a purely technical point of view. However, in power market conditions, equity and economics are also very important. That is to say, the scheme should be commercially fair. As in the single contingency condition, assume that the original generation dispatch is the most economic. The consequence of rescheduling (away from this economic dispatch state) is an increase of cost. The core of the problem is how to get the best control effect (the highest *GI*) at minimum cost. In other words, the optimization problem has two objectives that can be formulated as follows:

$$Min \sum \rho_{Gi} \left| \Delta P_{Gi} \right| \quad Max \sum_{m \in A, n \in B} C_{m \to n} \times G_{m \to n} \tag{3-7}$$

subject to:

$$\begin{aligned} & P_{Gi}^{\min} \le P_{Gi} + \Delta P_{Gi} \le P_{Gi}^{\max} \\ & \sum \Delta P_{Gi} = 0 \end{aligned}$$

As a technical objective is competing with an economic objective, there is no unique solution to the problem. Instead, the concept of noninferiority [131] (also called Pareto optimality [19] can be used to characterize the solution. A noninferior optimization point is one at which an improvement in any one objective requires a degradation of at least one other. In the multi-contingency case, there may not exist a control scheme that makes all of the candidate contingencies simultaneously secure. However, by comparing the *GI* value of different rescheduling schemes the best comprehensive stability enhancement schedule can be determined. In addition, using different weight coefficient μ^j, the problem of trade-off among the contingencies can be examined.

3.3 Numerical Examples

The implementation of the proposed generalized approach for improving transient security is illustrated through case studies on the New England 39-bus system [3]. The system has 10 generators, 39 buses and 46 tie-lines. Bus 31 has been chosen as the slack bus designated to make good transmission losses and is not involved in generation rescheduling. All the generators except that attached to the bus 31 (slack bus), which is not involved in generation rescheduling, are assumed as pool generators and all loads buy power from the pool. The initial real power outputs of generators and the corresponding bid prices are given in Table 3-1. Two severe candidate contingencies F_1, F_2 are selected. F_1 is a three-phase short circuit at bus-25 cleared by tripping line 25-26 in 0.22s. F_2 is a three-phase short circuit at bus-27 cleared by tripping line 26-27 in 0.22s. For F_1, only the generator at bus-39 is non-critical, the remaining generators are all critical, but for F_2, all generators expect those at bus-37 and bus-38 are non-critical. Hence generation shifts useful to both faults are from the generator at bus-37 and generator at bus-38 to the generator at bus-39 ($G_{37\to39}$ and $G_{38\to39}$). The sensitivity factors of these two power shifts and initial $CTEM$ for F_1 and F_2 are given in Table 3-2.

Table 3-1. Pool generator initial dispatch and price data

Bus-Name	Output (MW)	Bid Price ($/MWh)
30	250	16
32	650	8
33	632	7
34	508	12
35	650	8
36	560	9
37	540	4
38	830	15
39	1000	3

Table 3-2. Sensitivity factors and initial *CTEM* of the two faults

	λ_{37-39}	λ_{38-39}	$CTEM_0$
F_1	2.821	0.573	-1.147
F_2	0.362	1.978	-0.861

Table 3-3. Solutions for different μ^1

μ^1/μ^2	$(G_{37\to39}, G_{38\to39})$	*Cost*	$CTEM_E^1$	$CTEM_E^2$
>5	(0.5, 0.0000)	3.5	0.2638	-0.6802
5/1	(0.5, 0.0000)	3.5	0.2638	-0.6802
4/1	(0.5, 0.0000)	3.5	0.2638	-0.6802
3/1	(0.5, 0.0000)	3.5	0.2638	-0.6802
2/1	(0.5, 0.0000)	3.5	0.2638	-0.6802
1/1	(0.5, 0.0000)	3.5	0.2638	-0.6802
1/2	(0.5, 0.0299)	4.038	0.2810	-0.6210
1/3	(0.5, 0.0660)	4.688	0.3017	-0.5495
1/4	(0.5, 0.0850)	5.031	0.3126	-0.5120
1/5	(0.0, 0.2880)	5.184	-0.9818	-0.2907
1/6	(0.0, 0.2889)	5.200	-0.9814	-0.2890
<1/6	(0.0, 0.2889)	5.200	-0.9814	-0.2890

It is convenient to set the weight coefficient of F_2 (μ^2) to a constant value of unity and to deal with trade-off by adjusting the weight coefficient of F_1 (μ^1). In Table 3-3, the fourth column ($CTEM_E^1$) and the fifth column ($CTEM_E^2$) are the CTEM values after generation rescheduling. The example shows that there exist no schemes that can stabilize the system for both potential contingencies F_1 and F_2 at the same time. It can be seen that: 1) when μ^1/μ^2 is greater than one fourth, the optimum solution completely stabilize the system for F_1 but only partially for F_2; 2) no optimization schemes can completely satisfy the stabilization needs of F_2 because $G_{38\to39}$, which plays a more important role than $G_{38\to39}$, costs too much; 3) with the decrease of μ^1, the solution moves in a direction more beneficial for F_2; 4) for both faults, the security problem is improved to some degree after rescheduling. If μ^1/μ^2 ranges from 1/4 to 1/2, the optimization procedure reschedules both generators at bus-37 and bus-38. Outside this range the procedure makes use of only one generator. When F_1 is more important than F_2, the scheme prefers to use $G_{37\to39}$ because of its lower cost and better effect on the *GI*.

As the importance of F_2 increases, the scheme makes greater use of $G_{38\rightarrow39}$. When μ^1 / μ^2 is one fifth or less, the favorable technical effect of $G_{38\rightarrow39}$ exceeds the favorable economic effect of $G_{37\rightarrow39}$. In this case, the scheme only uses $G_{38\rightarrow39}$ for stability enhancement.

3.4 Summary

In this chapter, a generalized approach for transient security enhancement under multiple contingencies is developed for deregulated power systems. First, a GI is developed which can affect the global stability enhancement and deal with trade-off problem for multi-contingency condition. Then, according to the rules of power market, a technically sound and economically fair approach is developed to optimize the generation rescheduling scheme for the cases that several potentially unstable contingencies are taken into consideration. The approach is especially useful when there do not exist a scheme which can rescue all the candidate faults. Finally, simulation studies for the New England 39-bus system are carried out, and the results obtained demonstrate that the proposed approach is compatible with the deregulated competitive market structure.

4 MARKET-BASED REACTIVE POWER MANAGEMENT SCHEME

4.1 Introduction

It is well known that reactive power support is mandatory for active power transportations. Basically, the objectives of reactive power management could be briefly summarized as follows: 1) maintain adequate voltages throughout the power system under current and contingency conditions; 2) minimize congestion of real-power flows; 3) minimize active power losses.

Many reactive power devices (sources) are available in modern power systems. Different reactive power devices have different characteristics in terms of dynamics and speed of response, ability of withstanding system-wide voltages, capital costs, operating costs, and opportunity costs. For example, synchronous generators are generally very fast-acting reactive power support devices, but high opportunity costs may be incurred if active power outputs have to be reduced for producing reactive power. Opportunity cost of reactive power [78] is generally defined as the benefit or profit that could otherwise be harnessed, but has to be given up by the reactive power supplier in order to generate reactive power. On the other hand, capacitors are slow acting and have poor performance [27][72][73].

In vertically integrated power systems, all reactive power sources are owned by a single organization, i.e., the utility company concerned. As a result, reactive power support was part of the system operator's activities and the expenses incurred for providing such supports were included within the electricity tariff charged to end users. Reactive power management is the sole responsibility of the utility company, and there does not exist the problems of equitable procurement of reactive power support as well as cost allocations among different entities.

In the deregulated electricity market environment, reactive power management appears more difficult since different entities are involved in the reactive power support and hence equity is an important factor to consider for equitable procurement of reactive power support as well as cost allocations among different entities. Intuitively, ensuring sufficient reactive power resources for maintaining required level of voltages is becoming an increasingly difficult issue because of the disintegration of the electricity industry. Specifically, in the traditional vertically integrated power industry, generator reactive power resources, transmission reactive power resources, and the control center that determined when and which reactive power resources to be dispatched, are all owned by the utility company concerned. In the new environment, these may represent three different entities. Moreover, these entities may have different, even conflicting, goals. In particular, the owners of generator reactive power resources will be driven, in competitive generation markets, to maximize their own benefits from their resources. They may not be willing to sacrifice revenues from the sale of active power to produce reactive power unless appropriately compensated. Thus, an incentive mechanism appears necessary for the owners of reactive power sources to provide reactive power support services, and such a mechanism implies an adequate payment that guarantees the economic feasibility of this business. There are some disputes on if or not all kinds of reactive power resources should be compensated, and no generally applicable answer is available for this question since this should be dependent on the specific market models employed. In USA, only generator reactive power sources are entitled to such compensation by *Federal Energy Regulatory Committee* (FERC), in the form of ancillary service payment, as described in [121].

It is indicated in [63] that whenever the electricity supply industry is based on competitive markets, it seems reasonable to organize the ancillary services provision through the market-based procurement. Security constrained OPF models have been proposed for this purpose. Nevertheless, given the importance of ancillary services for reliability and quality of services, their complexity as well as specific technical characteristics, a significant degree of obligation and centralized control appears necessary. As an important kind of ancillary services, there is no exception for reactive power support.

Given this background, a centralized reactive power management scheme is presented in this chapter. Specifically, two problems are addressed: how to procure reactive power suppliers and how to handle the costs incurred, i.e., how to compensate suppliers and charge end users. Two kinds of reactive power suppliers are considered eligible for receiving financial compensations: generators with active power outputs and reactive power compensators. Reactive power compensators, assumed as assets of private investors, are treated as independent reactive power suppliers. Cost models of these two kinds of reactive power sources are firstly reviewed. Optimal reactive power dispatch is obtained with the objective of minimizing reactive power support cost. Then, a pricing structure including compensation to reactive power sources and charge of reactive power consumers is established with both technical feasibility and economic equitability taken into account. The idea of reactive power cost responsibility separation is applied to reactive power cost settlement, and the total reactive power cost is separated into two components. One component is for supporting active power transfer while another component is for the loading side reactive power consumption. The first cost component, which is considered as an obligation of the generation side, is allocated to different generators according to their corresponding active power participation factor. This factor is determined by the cost saving when there is no such active power selling. It means that a generator is not only a supplier of reactive power but is also a consumer of it. Compensation to a generator is the difference between the incurred cost of its reactive power contribution and the cost of its reactive power obligation for supporting active power transportation. The second component is recovered from load reactive power charge, which is based on its reactive power quantity consumed and the impacts of the load location concerned on the cost. It is assumed in this chapter that the ISO, as a facilitator of reactive power service, assures the total compensations to reactive power suppliers equal to the revenues from the reactive power consumers. Finally, a modified IEEE 14-bus test system is served for demonstrating the proposed reactive power management scheme.

4.2 Cost Analysis of Reactive Power

Reactive power costing models for generators with active power outputs and reactive power compensators are reviewed in this section. They are taken as reactive power ancillary service providers and will be incorporated in the reactive power pricing structure.

4.2.1 Reactive power cost of generators

Generators provide reactive power support by producing or consuming reactive power when operating at lagging or leading power factors, respectively. Unlike fuel costs that represent the operating cost of active power production there is only a small operating cost in the case of reactive power production and can normally be ignored. Hence, this chapter only considers the opportunity cost of generator reactive power production [78]. The opportunity cost of using a resource for a certain purpose is defined as the benefit lost for not using it in an alternative way. For example when a generator produces more reactive power, it has to reduce its active power production because of capacity constraints which will in turn reduce the opportunity of obtaining profits from an active power market. The profit of reduced active power production (implicit financial loss to generator) is modeled as the reactive power opportunity cost. The accurate model of such opportunity cost should be derived from the generator capacity curve which is also called the loading capability diagram. Opportunity cost also depends on the real time balance between demand and supply in the market and it may not be straightforward to determine its exact value. For illustrative purpose, a simplified generator reactive capability curve (Figure 4-1) is used to derive the opportunity cost.

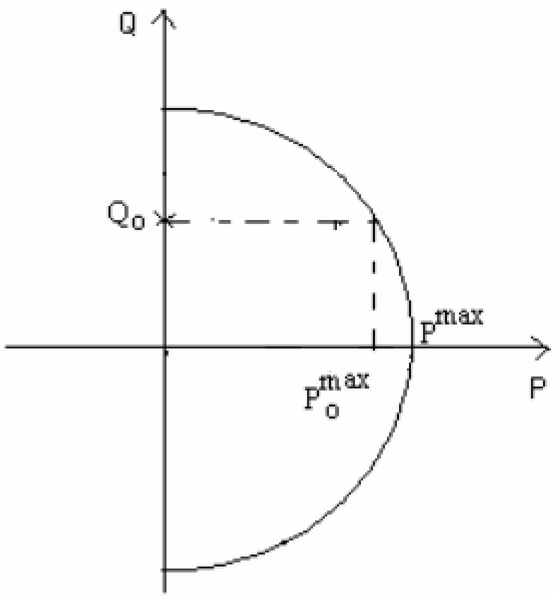

Figure 4-1. Simplified generator reactive capability curve

In Figure 4-1, $P^{\max}$ is active power output limit. Here it is set as the maximum apparent power ($S^{\max}$) of generator in this simplified model. When reactive power support of the generator is Q_0, its maximum possible active output is $P_o^{\max}$. Hence, the generator's capability of making profits in active power market decreases.

Here, the following simple model for opportunity cost is used:

$$C_{gqi}(Q_{gi}) = [C_{gpi}(S_{gi\max}) - C_{gpi}(\sqrt{S_{gi\max}^2 - Q_{gi}^2})]k_{gi} \tag{4-1}$$

where Q_{gi} is the reactive power output of generator g_i , S_{gimax} is the maximum apparent power of generator g_i, C_{gpi} is the active power cost which is modeled as a quadratic function($C_{gpi}(P_{gi}) = aP_{gi}^2 + bP_{gi} + c$ where P_{gi} is the active power output of g_i; *a, b and c are cost coefficients*); k_{gi} is an assumed profit rate for active power generation at bus *i*.

4.2.2 Cost of reactive power compensators

The charge for using reactive power compensators is assumed proportional to the amount of the reactive power purchased and can be expressed as:

$$C_{cj}(Q_{cj}) = r_j Q_{cj} \tag{4-2}$$

where r_j and Q_{cj} are the reactive power cost and the amount purchased, respectively, at location *j*. The production cost of a compensator is assumed as its capital investment return, which can be expressed as its depreciation rate. For example, if the investment cost of a reactive power compensator is \$6200/MVAr, and its average working rate and life span are 2/3 and 30 years respectively, the cost or depreciation rate of the compensator can be calculated as:

$r_j =$ Investment cost/Operating hours

$$= (\$6200)/(30 \times 365 \times 24 \times 2/3)$$
$$= \$0.0354/MVArhr$$

4.2.3 Limitation of the model

The model described above is correct only if it is assumed that use of static compensator entails a charge of this nature and if the opportunity cost of reactive power output from generators is non-zero. The former implies that reactive power compensators integrated into the transmission system are not included in equation (4-2) since their costs are included in use-of-system transmission charges. The latter is, strictly speaking, non-zero only for a generator on its MVA limit since; in this case, additional MVAR loading entails some MW reduction. These refinements are not incorporated in the model though it is possible to do so at the cost of some mathematical and algorithmic complexity.

4.3 Reactive Power Ancillary Services Procurement

Adequate reactive power support and voltage regulation services are necessary for enabling active power transactions. In the deregulated structure of the electricity industries, the competitive provision of reactive power raises the need to optimally allocate reactive power requirements among existing plants. The purpose of reactive power dispatch is to determine the proper amount and location of reactive power support in order to maintain a proper voltage profile and voltage stability requirement.

4.3.1 Reactive power optimization model

Objective:

$$\text{Min } C_Q = \sum_{i\in NG} C_{gqi}(Q_{gi}) + \sum_{i\in NC} C_{ci}(Q_{ci}) \tag{4-3}$$

where C_Q is the total reactive power support cost from generators and reactive power compensators; NG is the set of all generator buses and NC is the set of all reactive power compensator buses.

Constraints:

In the reactive power cost optimization, the active power output of generators is specified. The bus voltage, the reactive power output of generators and compensators are the control variables. The equality and inequality constraints, including the load flow equations, reactive power output of generators and compensators and the bus voltage limits in normal operating condition, are listed in equation (4-4)-(4-10).

$$P_{gi} = \left|\overline{V_i}\right| \sum_{j\in N} \left|\overline{V_j}\right| \left|Y_{ij}\right| \cos(\theta_{ij} + \delta_j - \delta_i) \tag{4-4}$$

$$-P_{Li} = \left|\overline{V_i}\right| \sum_{j\in N} \left|\overline{V_j}\right| \left|Y_{ij}\right| \cos(\theta_{ij} + \delta_j - \delta_i) \tag{4-5}$$

$$Q_{gi} = \left|\overline{V_i}\right| \sum_{j\in N} \left|\overline{V_j}\right| \left|Y_{ij}\right| \sin(\theta_{ij} + \delta_j - \delta_i) \tag{4-6}$$

$$Q_{ci} - Q_{Li} = \left|\overline{V_i}\right| \sum_{j\in N} \left|\overline{V_j}\right| \left|Y_{ij}\right| \sin(\theta_{ij} + \delta_j - \delta_i) \tag{4-7}$$

$$V_{i,\min} \le \left|\overline{V_i}\right| \le V_{i,\max} \tag{4-8}$$

$$Q_{gi,\min} \le Q_{gi} \le Q_{gi,\max} \tag{4-9}$$

$$Q_{ci,\min} \le Q_{ci} \le Q_{ci,\max} \tag{4-10}$$

where N is the total number of buses in the system; P_{Li} and Q_{Li} are the specified active and reactive demand at load bus i ; $Y_{ij}\angle\theta_{ij}$ is the element of the admittance matrix; $\overline{V_i} = V_i\angle\delta_i$ is the bus voltage at bus i ; $V_{i,\min}$ and $V_{i,\max}$ are the lower and upper limits of bus voltage; $Q_{gi,\min}$ and $Q_{gi,\max}$ are the lower and upper limits of reactive power output of the generator; and $Q_{ci,\min}$ and $Q_{ci,\max}$ are the lower and upper limits of reactive power output of the compensators.

<u>*Reactive OPF Outputs:*</u>

The solution of the above reactive OPF formulation from equations (4-3) to (4-10) includes minimum reactive power support cost (C_Q^*), reactive power amounts (Q_{gi}^*, Q_{ci}^*) purchased from different suppliers and their incurred costs (C_{gqi}^*, C_{ci}^*). The Lagrange multipliers (λ_{Li}) of the reactive power load equality constraints can also be obtained which will be used for evaluating load reactive charge as described in *Section 4.4*.

4.3.2 Computation aspects

The reactive OPF model formulated in *Section 4.3.1* is a *non-linear programming* (NLP) problem. There is no general method to solve the NLP problem. The chapter adopts the *sequential quadratic programming* (SQP) method [65]. The SQP method transfers the original NLP problem to sequential QP (Quadratic Programming) sub-problems. Through iterations, the solution for the original problem will be gradually reached. For the following standard form of NLP problem:

$$\text{Min } f(x)$$

subject to: $\begin{pmatrix} g_i(x) = 0, & i = 1,2,\cdots p \\ h_i(x) \le 0, & i = 1,2,\cdots m \end{pmatrix}$

The SQP algorithm can be briefly illustrated as:

1. Set $k=0$. Choose a starting point x^0

2. Set up and solve the following QP sub-problem for direction d

$$\text{Min } \nabla f(x^k)^T d + \frac{1}{2} d^T d$$

$$\text{subject to: } \begin{pmatrix} g_i(x^k) + \nabla g_i(x^k)^T d = 0, \quad i = 1,2,\cdots p \\ h_i(x^k) + \nabla h_i(x^k)^T d \le 0, \quad i = 1,2,\cdots m \end{pmatrix}$$

3. Set the new point as: $x^{k+1} = x^k + d$

4. If $\|d\| \le \varepsilon$ (a small number), stop. Otherwise, set $k=k+1$ and go to step 2

4.4 Reactive power support cost settlement

A novel pricing scheme for reactive power is presented in this section. The scheme is comprised of five steps based on the proposed reactive power responsibility identifications.

1) Reactive power support cost responsibility separation

The total reactive power cost is divided into two components, namely the generators side and the loads side. The duty cost of the generators side C_G (i.e. the reactive power cost to support the delivery of active power) is calculated as the optimal value of equation (4-3) when the system has no reactive loads. To evaluate this cost, the power factors of all the loads are set to unity. This component of cost is caused only by active power transportation. The remaining cost ($C_L = C_Q^* - C_G$) is assigned to reactive loads.

2) Equitable allocation of C_G to generators

In this step, the power factors of all loads are kept at unity. Due to various location and active power output of generators, their respective reactive power requirements are different. Cost saving concept is introduced here for equitable allocation of C_G to generators. The cost saving (S_{gi}) of the i^{th} generator is defined as the difference between $C_{P_{gi}=0}$ and C_G ($S_{gi} = C_G - C_{P_{gi}=0}$) where $C_{P_{gi}=0}$ is the optimal value of equation (4-3) when P_{gi} is set to zero. The more the cost saving is, the more the reactive power requirement of the corresponding generator. It should be noted that the total loads need to be cut the same amount as P_{gi} when equation (4-3) is solved under this condition. This chapter uses a simple way to distribute it to different loads. The j^{th} load decrease is expressed as $\Delta P_{Lj} = \frac{P_{Lj}}{\sum P_{Lj}} P_{gi}$. After the same process has been applied to all the other generators, the cost allocation factor for the i^{th} generator is calculated as $\eta_{gi} = \frac{S_{gi}}{\sum S_{gi}}$. The duty cost of the i^{th} generator can be expressed as $D_{gi} = \eta_{gi} C_G$.

3) Payment to generators (R_{gi})

The payment to the i^{th} generator is the difference between the actual incurred cost of its reactive power contribution and its allocated duty cost for active power transportation:

$$R_{gi} = C_{gqi}^* - D_{gi}. \tag{4-11}$$

4) Charge of reactive loads (W_{Li})

$$W_{Li} = \frac{\lambda_{Li} Q_{Li}}{\sum \lambda_{Li} Q_{Li}} C_L \tag{4-12}$$

The charge has taken the effects of the loading location and revenue reconciliation requirement into account.

5) Payment to independent reactive power sources (R_{ci})

The payment to an independent reactive power source *i*, which has no participation in active power market, should be equal to its incurred cost:

$$R_{ci} = C_{ci}^{*} \tag{4-13}$$

Integrating the procurement model and these settlement steps, the whole process of reactive power management is depicted in Figure 4-2.

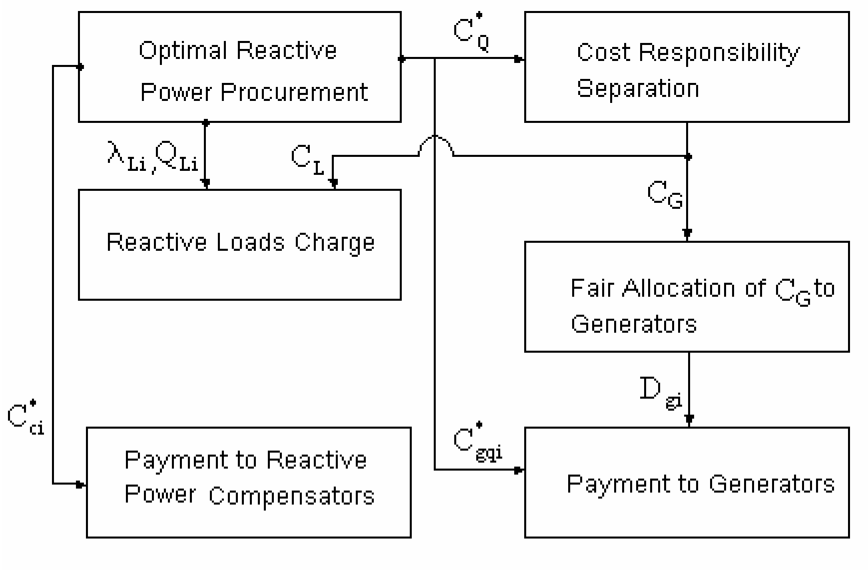

Figure 4-2. Flowchart of reactive power management scheme

4.5 Case Studies

A modified IEEE 14-bus system (the single line diagram is given in *Appendix A*) is used for computer simulation studies. The system has 3 generators, 14 buses and 20 tie lines. Two independent reactive power compensators are located at bus 6 and bus 8 respectively. Bus 1 is selected as slack bus. The generator attached to the bus is designated to make good transmission loss changes and its reactive power cost is not included in the optimization procedure. The system base capacity is 100 MVA. Data of generators are given in Table 4-1.

Table 4-1. Generators data

Generator Location	Bus 2 (G_2)	Bus 3 (G_3)
Maximum Apparent Power (p.u.)	0.9	0.9
Active Power Output (p.u.)	0.6	0.74
Reactive Power Limit (p.u.)	[-0.4,0.5]	[-0.5,0.4]
Profit Rate(p.u.)	0.07	0.07
Active Power Cost Function ($/hr)	$45+750P_i+450P_i^2$	

Capacity and depreciation coefficient of reactive power compensators are listed in Table 4-2. Loads data are given in Table 4-3. Transmission lines data and transformers data same as the standard data are given in Tables A-1 and A-2, respectively.

Table 4-2. Depreciation rates of reactive power compensators

Compensator Location	Bus 6 (IC_6)	Bus 8 (IC_8)
Maximum Capacity (p.u.)	0.3	0.3
Depreciation Coefficients ($/*MVAR*·hr)	.10	.10

Table 4-3. Loads data

Bus No.	4	5	9	10	11	12	13	14
Real Load (p.u.)	0.478	0.076	0.595	0.090	0.035	0.066	0.150	0.150
Reactive Load (p.u.)	0.039	0.016	0.024	0.058	0.018	0.016	0.058	0.05

The optimization process *described* in *Sections 4.3* are executed for four different cases and the corresponding generator reactive power outputs and system reactive power costs are listed in Table 4-4.

Table 4-4. Optimum reactive power dispatch

Operating Condition	Reactive Power Output (p.u.)				Reactive power Cost($/hr)
	G_2	G_3	IC_6	IC_8	
Base Case	0.086	0.086	.157	128	C_Q^* =3.760
Q_{Li}=0.0	0.082	0.082	0.00	0.001	C_G=0.893
Q_{Li}=0.0 and P_{G2}=0.0	0.036	0.037	0.00	0.00	$C_{pg2=0.0}$=0.163
Q_{Li}=0.0 and P_{G3}=0.0	0.016	0.016	0.00	0.00	$C_{pg3=0.0}$=0.03

From the reactive power costs in the last column of Table 4-4, the cost allocation factors of the generators can easily be obtained as $\eta_{g2} = 0.45$, $\eta_{g3} = 0.55$. Generator G_2 is responsible for forty-five percent of C_G while G_3 is responsible for the remaining. The cost duty of loads can also be calculated as 2.867($/hr). The Lagrange multipliers (in base case) and reactive power charges of reactive power loads are provided in Table 4-5.

Table 4-5. Reactive load charges

Bus No.	4	5	9	10	11	12	13	14
Lagrange Multiplier Associated with Reactive Load	105.617	105.164	106.285	105.681	105.728	103.289	101.789	104.231
Charge ($/hr)	0.405	0.166	0.251	0.602	0.187	0.163	0.579	0.514

Payment to generators and reactive power compensators are given in Table 4-6.

Table 4-6. Payment to generators and reactive power compensators

	Cost of real power transport duty ($/hr)	Cost of reactive power contribution ($/hr)	Payment ($/hr)
G_2	0.403	0.450	0.047
G_3	0.490	0.450	-0.04
IC_6	----	1.571	1.571
IC_8	----	1.287	1.287

Reactive power compensators receive all their reactive power support costs. For active power sellers, only part of the reactive power support cost will be compensated. It should be noted that payment to generator G_3 is negative because the cost of reactive power support provided by G_3 is smaller than the reactive power cost of supporting active power transportation allocated to it. In other words G_3 has to pay ISO for its active power selling. It can also be observed from Table 4-6 that a rather high percentage of reactive power charge is used to compensate independent reactive power compensators in this case.

4.6 Summary

A centralized market model for reactive power management is developed in this chapter. Basically, a cost based mechanism is employed in the proposed scheme. First, a modified reactive OPF model is developed to solve the optimal reactive power dispatch problem. Reactive power responsibilities are equitably shared and priced among generators and loads concerned. Specifically, the total reactive power support cost is separated into generators' duty and loadings' duty. Cost duty on the generation side is allocated to active power sellers by evaluating their reactive power requirements for active power transportations. The evaluation method adopted has a common basis for every market participant and hence it is consistent and equitable. Each generator will be paid according to the difference between its actual incurred cost in reactive power support and its cost of reactive power requirement for its own active power transportations. Charges for reactive loads consider both locations and the amounts of reactive power demands. The proposed model and method are demonstrated through an IEEE system. The results obtained illustrate that the proposed transparent reactive power management scheme is compatible with the new competitive market structure, and economic efficiency could be achieved.

5 PRICING OF REACTIVE POWER ANCILLARY SERVICES

5.1 Introduction

In *Chapter 4*, a new reactive power management scheme is proposed. The main feature of this scheme is that part of the total reactive power support cost is deemed as the duty of generators. Each generator participating in the active power market concerned is assigned a certain reactive power obligation. Such an arrangement ensures adequate reactive power support be available to the system dispatcher such as ISO. The remaining part of reactive power support cost is recovered from reactive loads. In this chapter, a more specific subject, namely, pricing of reactive power ancillary services will be investigated in detail. It is assumed that generators are fully compensated for their profit losses due to reactive power support provision. It should be mentioned that in this chapter the reactive power ancillary services defined by FERC [121] is strictly followed, i.e., only reactive power support from generating devices is treated as an ancillary service. Cost of reactive power support from transmission devices is recovered by transmission charges.

Reactive power pricing is a fundamental and very important part of reactive power management. Analyzing the costs of reactive power service provisions and establishing an appropriate pricing structure are important both financially and operationally for the deregulated power industry. First, correct price signals are very important for facilitating transmission access and improving economic efficiency. With proper costing and pricing of reactive power, transmission users will have the ability to make decisions strategically on some economic activities such as energy transactions, investments, and asset utilization. Second, the operation efficiency and reliability of the power system concerned will be improved when well-balanced and appropriately distributed reactive power sources are available. Third, voltage profiles will be improved which, in turn, will reduce possibilities of incidents caused by high and low voltage problems, and even, voltage instability in some extreme cases.

Much research work has been done on reactive power pricing, and as a result many methods concerned have been developed. Among the existing methods, the marginal cost theory based reactive power pricing is well established, and represents an extension of the elegant active power spot pricing theory [18]. An early attempt on this aspect could be found in [6]. A decoupled OPF model was proposed for active and reactive power pricing in [42]. In-depth theoretical investigation on applying the marginal cost concept to the real-time pricing of reactive power was carried out in [7]. Detailed cost models of reactive power support could be found in [78] and a similar approach based on the opportunity cost of dispatching reactive power from generators was presented in [32][33]. However, as pointed out in [66][67], the marginal cost based reactive power pricing method is not suitable for practically operated electricity markets due to the volatility and erratic behavior of the prices such obtained. Moreover, the marginal cost based pricing method may not be able to recover the costs, since the investment cost represents a major part of reactive power support service. An alternative way for reactive power pricing is to formulate it as a reactive power support cost allocation problem. Reactive power tracing [10], the graph theory based method [126] and the modified Y-Bus method [25] could be classified into this category. This kind of methods attempts to charge market participants by determining the quantity of reactive power that each reactive power source contributes to each individual load. However, the inherent coupling between active power and reactive power flows makes the determination of these so-called contribution factors quite difficult both in theory and algorithm implementation, and hence some simplifications have to be made.

In this chapter, the reactive power pricing problem is expressed as a joint cost allocation problem. It is assumed that the system dispatcher or ISO takes the responsibility of procuring the required reactive power support service, with both technical feasibility and economic efficiency into account. The costs incurred for reactive power support are fully allocated to consumers in an equitable and transparent manner. The reactive power support cost of an individual generator is measured by its opportunity cost, which is evaluated by its profit loss in the active power market. The opportunity cost is precisely determined through the possible rescheduling by the ISO. Specifically, under the assumptions that the total system active power output and active power market clearing price remain unchanged, the total reactive power support cost (the summation of the reactive power support costs from all generators concerned) equals to the difference of active power production costs between the situations without and with reactive power as well as voltage constraints taken into account. Cost allocation factors for active loads and reactive loads are then calculated with the application of the well-known *Aumann-Shapley* (A-S) method [11][12][91] from game theory.

5.2 Determination of Reactive Power Support Cost

Maintaining a proper system voltage profile in both normal and contingent states requires sufficient provision and reserves of reactive power. On the other hand, effective management of reactive power is vital to the operation of the power market concerned. The first issue related to the reactive power pricing to be considered is the identification of the reactive power support cost requirements. In this chapter, such cost is measured as the increase in the cost of producing active power from the base case (with network constraints neglected) to the case with reactive power and voltage constraints considered.

5.2.1 Base case active power scheduling

Mathematically, the active power scheduling problem in the base case, as defined before, could be formulated as

$$F^U(\overline{P}_d) = \mathrm{Min} \sum_{i \in NG} C_{pg_i}(P_{g_i}) \tag{5-1}$$

subject to:

$$\sum_{i \in NG} P_{g_i} - \sum_{j \in N} P_{d_j} = 0$$

$$0 \le P_{g_i} \le P_{g_i \max},$$

where NG is the set of all generator buses; and $C_{pg_i}(P_{g_i})$ is the active power production "cost" function of the generator at bus i constructed from generation bids (it is approximated as a quadratic function $C_{pg_i}(P_{g_i}) = a_{g_i} + b_{g_i} P_{g_i} + c_{g_i} P_{g_i}^2$ under the assumption that the generator bids at its marginal cost $B_{pg_i}(P_{g_i}) = b_{g_i} + 2c_{g_i} P_{g_i}$); P_{g_i} is the generation of active power at bus i; N is the set of all of the buses; $\overline{P}_d = \lfloor P_{d_1} \quad \ldots \quad P_{d_j} \quad \ldots \quad P_{d_N} \rfloor$ is an N dimensional active power load vector and its i^{th}

element P_{d_i} is the active power load at bus i; and $P_{g_i,\max}$ is the active power upper limit of the generator at bus i. The solution of this model includes the dispatch of active power ($\overline{P}_g^u = \begin{bmatrix} P_{g_1}^u & \ldots & P_{g_i}^u & \ldots & P_{g_{NG}}^u \end{bmatrix}$), the minimum active power production cost $F^U(\overline{P}_d)$, and the market clearing price λ (the Lagrange multiplier associated with the power balance equation) in the unconstrained case (regarding network limitations). This base case is used as a reference for an analysis of the costs of reactive power support. The real generation schedule that is obtained may not be feasible when network constraints are considered. In this chapter, the emphasis is placed on the reactive power/voltage constraints. The generation of active power may need to be re-scheduled out of merit in order to satisfy these constraints. In this case the active power problem and the reactive power problem have to be handled simultaneously. A modified OPF model is proposed for this purpose.

5.2.2 Active power and reactive power co-optimization

Objective:

$$F^C(\overline{P}_d, \overline{Q}_d) = \text{Min} \sum_{i \in NG} C_{pg_i}(P_{g_i}) \tag{5-2}$$

This is to minimize the costs of producing active power, similar to the objective described in problem (5-1).

Equality Constraints:

Two sets of equations, including the normal and contingent states, governed by Kirchhoff's laws that characterize flows of power throughout the system, are expressed as:

$$\left.\begin{aligned} P_{g_i} - P_{d_i} &= \left|\dot{V}_i\right| \sum_{j \in N} \left|\dot{V}_j\right| \left|Y_{ij}\right| \cos(\theta_{ij} + \delta_j - \delta_i) \\ Q_{g_i} - Q_{d_i} &= \left|\dot{V}_i\right| \sum_{j \in N} \left|\dot{V}_j\right| \left|Y_{ij}\right| \sin(\theta_{ij} + \delta_j - \delta_i) \end{aligned}\right\rangle \text{(Normal State)}$$

$$\left.\begin{aligned} P_{g_i} - P_{d_i} &= \left|\dot{V}_i{}'\right| \sum_{j \in N} \left|\dot{V}_j'\right| \left|Y_{ij}'\right| \cos(\theta_{ij}' + \delta_j' - \delta_i') \\ Q_{g_i}' - Q_{d_i} &= \left|\dot{V}_i{}'\right| \sum_{j \in N} \left|\dot{V}_j'\right| \left|Y_{ij}'\right| \sin(\theta_{ij}' + \delta_j' - \delta_i') \end{aligned}\right\rangle \text{(Contingent State),}$$

where $\overline{Q}_d = \lfloor Q_{d_1} \quad \dots \quad Q_{d_j} \quad \dots \quad Q_{d_N} \rfloor$ is the reactive load vector and its i^{th} element Q_{d_i} is the reactive demand at bus i; Q_{g_i} is the reactive power generated at bus i; $Y_{ij}\angle\theta_{ij}$ is the element of the admittance matrix; and $\dot{V}_i = V_i\angle\delta_i$ is the bus voltage at bus i. Variables with superscript represent the corresponding values in the state of contingency.

Voltage Limits

$$V_{i,\min} \le \left|\dot{V}_i\right| \le V_{i,\max} \quad \forall i \in N$$

$$V_{i,\min}' \le \left|\dot{V}_i'\right| \le V_{i,\max}' \quad \forall i \in N\ ,$$

where $V_{i,\min}$ and $V_{i,\max}$ are the lower and upper voltage limits in the normal state while $V_{i,\min}'$ and $V_{i,\max}'$ are the lower and upper voltage limits in the contingent state. Voltage requirements in the normal state are normally stricter than that in the contingent state.

Generator's capacity limits:

$$P_{g_i}^2 + Q_{g_i}^2 \le S_{g_i,\max}^2$$

$$P_{g_i}^2 + Q_{g_i}'^2 \le S_{g_i,\max}^2$$

$$P_{g_i} \ge 0$$

where $S_{g_i,\max}$ is the maximum apparent power of the generator at bus *i*. For the sake of clear illustration, a simplified circular loading capability diagram is assumed for a generator and the active power up limit $P_{g_i\max}$ is equal to the maximum apparent power $S_{g_i,\max}$.

As a result of the adoption of the preventive control concept, the active power outputs of generators in the normal and contingent states are the same. Reactive power capabilities reserved in the generators are sufficient to maintain system voltages under a specified contingency. Re-scheduled active power generation vector $\overline{P}_g^C = \begin{bmatrix} P_{g_1}^C & \ldots & P_{g_i}^C & \ldots & P_{g_{NG}}^C \end{bmatrix}$ and the minimum real production costs $F^C(\overline{P}_d, \overline{Q}_d)$ taking voltage security constraints into account can be obtained. The SQP method [65] is used to solve this non-linear optimization problem (5-2).

5.2.3 *Active power settlement and reactive power support costs*

As discussed previously active power generations may be rescheduled due to the reactive power support requirements. Generators' profits from active power selling are affected consequently. It is assumed in this chapter that the uniform market clearing price obtained in the base case is used for active power settlement, even after generations rescheduling. The profit change of generator *i* can be expressed as:

$$\Delta\rho_{g_i} = [\lambda P_{g_i}^U - C_{pg_i}(P_{g_i}^U)] - [\lambda P_{g_i}^C - C_{pg_i}(P_{g_i}^C)] \tag{5-3}$$

The effects of rescheduling on a generator's profits in active power market are discussed in the following according to its base case schedule.

a) $0 < P_{g_i}^U < P_{g_i,\max}$

In this case, the generator's bid price (its marginal cost) at $P_{g_i}^U$ is equal to the market clearing price, $b_{g_i} + 2c_{g_i} P_{g_i}^U = \lambda$. When the generator is requested by the ISO to decrease its scheduled active power output ($P_{g_i}^C < P_{g_i}^U$, a constrained-off generator), its income decrease, $\lambda(P_{g_i}^U - P_{g_i}^C)$, is larger than its active power production cost decrease, $b_{g_i}(P_{g_i}^U - P_{g_i}^C) + c_{g_i}(P_{g_i}^U - P_{g_i}^C)(P_{g_i}^U + P_{g_i}^C)$. Conversely, when the unused capacity of a generator is called on by the ISO to balance the system active power insufficiency ($P_{g_i}^C > P_{g_i}^U$, a constrained-on generator), the increase in active power production cost is larger than that in income. Hence the generator's profit decreases no matter the generator is constrained on or off. This is illustrated in Figure 5-1. Shaded areas 1 and 2 represent the profit losses in the cases of constrained-off and constrained-on, respectively.

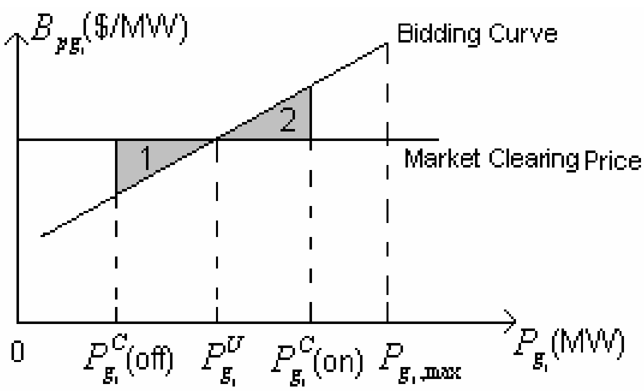

Figure 5-1. Lost profit illustration when $0 < P_{g_i}^U < P_{g_i,\max}$

b) $P_{g_i}^U = 0$

The generator can only be requested to increase its output in this case and its generation bid is higher than the market-clearing price. The active power production cost increase is larger than the income increase. The generator is subject to profit loss (shaded area in Figure 5-2).

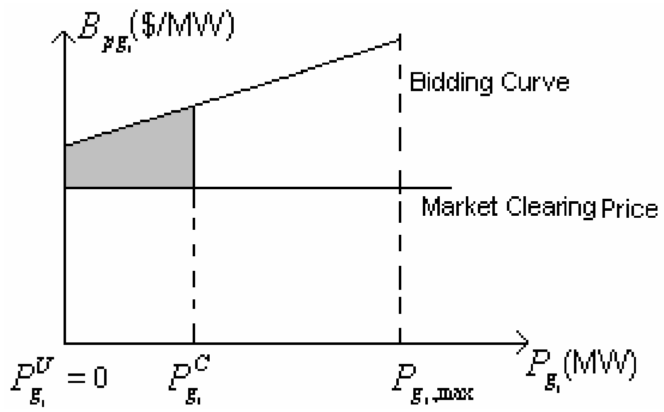

Figure 5-2. Lost profit illustration when $P_{g_i}^U = 0$

c) $P_{g_i}^U = P_{g_i,\max}$

In this case, the active power output hits the upper limit. The generator can only be requested to decrease its output and its generation bid is lower than the market clearing price. The generator is also subject to profit loss (shaded area in Figure 5-3) as the active power production cost decrease is less than that of the income.

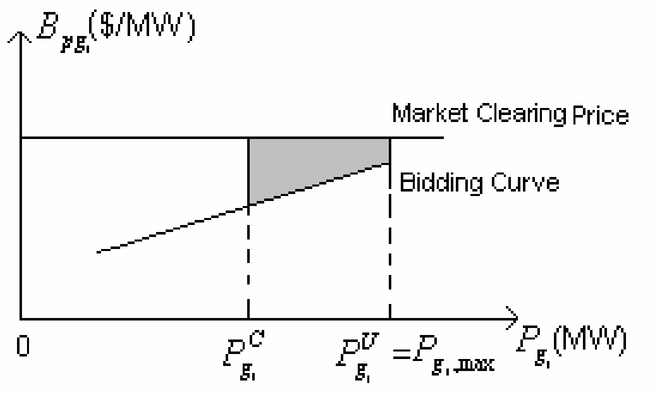

Figure 5-3. Lost profit illustration when $P_{g_i}^U = P_{g_i,\max}$

It can be concluded that the generator will be subject to profit loss ($\Delta\rho_{g_i} > 0$) if its real output has to be rescheduled away from the base case. This profit loss can also be called as the generator's opportunity cost for reactive power support.

To ensure the required reactive power support is provided, the ISO needs to compensate a generator the opportunity cost making it indifferent whether generating active power or providing reactive power support. The total amount that the ISO has to pay for reactive power support is the summation of all generators' opportunity costs, which is defined as the total system reactive power support costs ($F_Q = \sum_{i \in NG} \Delta\rho_{g_i}$). Substituting equation (5-3) into this equation, $F_Q = \lambda(\sum_{i \in NG} P_{g_i}^U - \sum_{i \in NG} P_{g_i}^C) + \sum_{i \in NG} C_{pg_i}(P_{g_i}^C) - \sum_{i \in NG} C_{pg_i}(P_{g_i}^U)$.

If transmission real losses are neglected, system total real output remains unchanged. It also implies that it is not necessary to curtail loads to ensure system voltage security. Hence, the total system reactive power support cost can be expressed as the increase of active power production cost:

$$F_Q = F^C(\overline{P}_d, \overline{Q}_d) - F^U(\overline{P}_d) \tag{5-4}$$

The incurred cost F_Q of providing reactive power support needs to be recovered from system users. The reactive power support cost allocation problem is described in the next section.

5.3 Reactive Power Support Cost Allocation Factors

The procurement of reactive power support services and the calculation of the corresponding cost have been discussed in the last section. In the process of procurement, the ISO on behalf of all consumers buy sufficient reactive power support based on the least cost criterion. Reactive power support is centrally dispatched and treated as a common service from the perspective of voltage control. Another aspect related to reactive power management is how to charge different consumers according to their need of reactive power support requirement. It is formulated as a joint cost allocation problem in this chapter. Joint cost allocation problems arise in many contexts in economics and management science. In a typical problem that we have in mind, a decision maker must decide how to allocate the joint cost of service among several consumers. Both direct consumption of reactive power and indirect consumption of reactive power accompanied with the use of active power need system reactive power support and consequently have responsibilities to share the cost. So there should be two prices corresponding to real load and reactive load of a consumer. Furthermore, these prices must satisfy cost recovery requirement, i.e. total revenue generated from these prices must be able to cover the total cost. Given a loading condition, it can be expressed as: $F_Q = \sum_{i=1}^{N}(\eta_{P_{d_i}} \times P_{d_i} + \eta_{Q_{d_i}} \times Q_{d_i})$ where $\eta_{P_{d_i}}$ and $\eta_{Q_{d_j}}$ are reactive power cost allocation factors (prices) for real load and reactive load at bus *i*, respectively. The vector form of this equation is:

$$F_Q = \overline{D} \bullet \overline{\eta} \tag{5-5}$$

where $\overline{D} = [\overline{P}_d, \overline{Q}_d]$ is a $2N$ dimensional demand vector including both real and reactive loads; $\overline{\eta} = [\overline{\eta}_{P_d}, \overline{\eta}_{Q_d}]$ is a price vector of the same dimension ($\overline{\eta}_{P_d} = [\eta_{P_{d_1}} \quad \cdots \quad \eta_{P_{d_i}} \quad \cdots \quad \eta_{P_{d_N}}]$, $\overline{\eta}_{Q_d} = [\eta_{Q_{d_1}} \quad \cdots \quad \eta_{Q_{d_i}} \quad \cdots \quad \eta_{Q_{d_N}}]$).

The well-developed *Aumann-Shapley (A-S)* pricing method, which is described in detail in the *Appendix B*, falling in the category of axiomatic approaches is adopted in this chapter to calculate the price vector $\overline{\eta}$. Using equation (B-1) in the *Appendix B*, A-S prices related to the real and reactive loads of the consumer at bus *i* can be expressed as:

$$\eta_{P_{d_i}} = \int_0^1 \frac{\partial F_Q(t\overline{D})}{\partial P_{d_i}} dt \tag{5-6}$$

$$\eta_{Q_{d_i}} = \int_0^1 \frac{\partial F_Q(t\overline{D})}{\partial Q_{d_i}} dt \tag{5-7}$$

where $\frac{\partial F_Q(t\overline{D})}{\partial P_{d_i}}$ and $\frac{\partial F_Q(t\overline{D})}{\partial Q_{d_i}}$ are marginal costs of real and reactive loads evaluated at demand level $t \in [0,1]$, respectively. To find these two definite integrals analytically is very difficult because the analytical expression of the integrands will not be available. However, we can obtain the marginal costs at different demand levels by solving the optimization problems (5-1) and (5-2):

$$\frac{\partial F_Q(t\overline{D})}{\partial P_{d_i}} = \frac{\partial F^C(t\overline{D})}{\partial P_{d_i}} - \frac{\partial F^U(t\overline{D})}{\partial P_{d_i}} = \pi'_{P_{d_i}}(t\overline{D}) + \pi_{P_{d_i}}(t\overline{D}) - \lambda(t\overline{D}) \tag{5-8}$$

$$\frac{\partial F_Q(t\overline{D})}{\partial Q_{d_i}} = \frac{\partial F^C(t\overline{D})}{\partial Q_{d_i}} = \pi'_{Q_{d_i}}(t\overline{D}) + \pi_{Q_{d_i}}(t\overline{D}) \tag{5-9}$$

where $\pi'_{P_{d_i}}(t\overline{D})$ and $\pi_{P_{d_i}}(t\overline{D})$ are the Lagrange multipliers associated with the active power balance equations at bus *i* of problem (5-2) in normal and contingent sets at demand level t, respectively; $\lambda(t\overline{D})$ is the unconstrained market clearing price (active power) at demand level t; $\pi'_{Q_{d_i}}(t\overline{D})$ and $\pi_{Q_{d_i}}(t\overline{D})$ are the Lagrange multipliers associated with the reactive power balance equations at bus *i* of problem (5-2) in normal and contingent sets at demand level t, respectively. It should be noted that as reactive power demands have no effects on the base case dispatch ($\frac{\partial F^U}{\partial Q_{d_i}} = 0$), the reactive power marginal costs in equation (5-9) only use information of problem (5-2). Hence, a numerical approach can be used to solve equations (5-6) and (5-7). Numerical approximations of $\eta_{P_{d_i}}$ and $\eta_{Q_{d_i}}$ are given by:

$$\eta_{P_{d_i}} = \frac{1}{K}\sum_{k=1}^{K}[\pi'_{P_{d_i}}(\frac{k}{K}\overline{D}) + \pi_{P_{d_i}}(\frac{k}{K}\overline{D}) - \lambda(\frac{k}{K}\overline{D})] \tag{5-10}$$

$$\eta_{Q_{d_i}} = \frac{1}{K}\sum_{k=1}^{K}[\pi'_{Q_{d_i}}(\frac{k}{K}\overline{D}) + \pi_{Q_{d_i}}(\frac{k}{K}\overline{D})] \tag{5-11}$$

where K is the number of numerical integration steps. Problems (5-1) and (5-2) have to be solved K times sequentially to calculate A-S prices. Indeed, A-S prices are average marginal costs concerning all level of the demand vector, but a constant mix of each component (real loads and reactive loads increasing at the same speed) is needed.

Normally, reactive power support cost F_Q has a positive relation with the level of demand. F_Q is zero when there is no voltage congestion under light loading condition. There exists a critical demand level satisfying $F_Q(t\overline{D}) = 0, t \le t_0$ and $F_Q(t\overline{D}) > 0, t > t_0$. This is illustrated in Figure 5-4 using the test system described in *Section 5.4*.

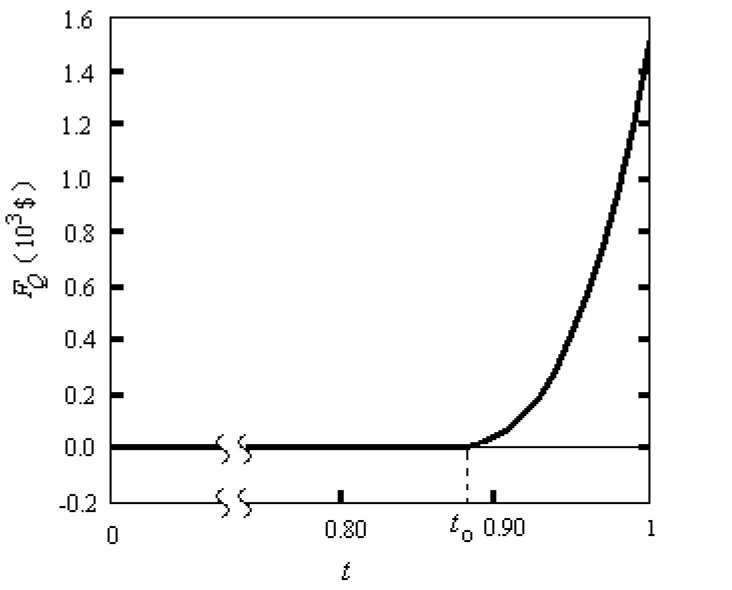

Figure 5-4 Reactive power support cost as a function of demand level

Demand changes under t_0 have no effect on the reactive power support costs. The interval $[t_0,1]$ is the effective integration region. A preliminary identification of t_0 would improve the computation efficiency in practice. The bisection method, which is commonly adopted in polynomial root finding [4], is used for this purpose. Given this new start point t_0 of numerical integration, equations (5-10) and (5-11) can be rewritten as:

$$\eta_{P_{d_i}} = \frac{1-t_0}{K}\sum_{k=1}^{K}[\pi'_{P_{d_i}}((t_0+kh)\bar{D}) + \pi_{P_{d_i}}((t_0+kh)\bar{D}) - \lambda((t_0+kh)\bar{D})] \tag{5-12}$$

$$\eta_{Q_{d_i}} = \frac{1-t_0}{K}\sum_{k=1}^{K}[\pi'_{Q_{d_i}}((t_0+kh)\bar{D}) + \pi_{Q_{d_i}}((t_0+kh)\bar{D})] \tag{5-13}$$

where $h=(1-t_0)/K$ is the step size. Obviously, the approximation accuracy of these two equations is higher than that of equations (5-10) and (5-11) with the same computation burden (K times of base case and reactive power optimizations).

5.4 Case Studies

A simple 8-bus system as shown in Figure 5-5 is used for computer simulation studies. The system has 8 buses and 9 tie lines. There are three generators and four consumers in the system. Their data is summarized in Table 5-1 and Table 5-2, respectively. Table 5-3 gives transmission line data. The system base capacity is 100 MVA. The voltage limits are all within the range $0.95 \le V_i \le 1.05$ (p.u.)($i = 1,2,\cdots 8$). Bus 8 is selected as the angle reference bus.

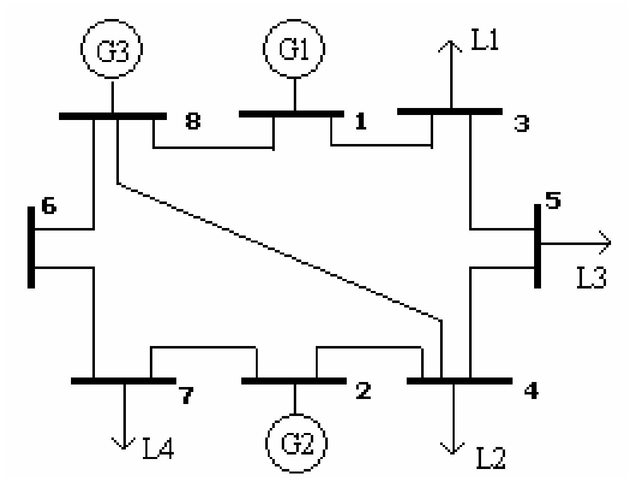

Figure 5-5. 8-bus test system

Table 5-1. Generators data of 8-bus system

Generator Location	Bus 1 (G_1)	Bus 2 (G_2)	Bus (G_8)
Maximum Apparent Power(p.u.)	2.0	3.0	5.0
Active Power Cost Function ($/hr)	$500P_{g_1} + 300P_{g_1}^2$	$550P_{g_2} + 400P_{g_2}^2$	$600P_{g_3} + 450P_{g_3}^2$

Table 5-2. Consumers data of 8-bus system

Consumer	Bus No.	Real Load (p.u.)	Reactive Load (p.u.)
L_1	3	0.50	0.31
L_2	4	3.00	1.85
L_3	5	1.50	0.93
L_4	7	2.00	1.24

Table 5-3. Transmission lines data of 8-bus system

From	To	Resistance (p.u.)	Reactance (p.u.)	Susceptance (p.u.)
1	3	0.00	0.037	-0.06
1	8	0.00	0.03	-0.06
2	4	0.00	0.031	-0.06
2	7	0.00	0.03	-0.06
3	5	0.00	0.037	-0.06
4	5	0.00	0.05	-0.06
4	8	0.00	0.03	-0.06
6	7	0.00	0.03	-0.06
6	8	0.00	0.015	-0.06

The base (unconstrained) case active power dispatch is given in Table 5-4.

Table 5-4. Base case active power dispatch

Active power Generation (p.u.)			Total Real Production Cost F^U (10^3\$/h)	Market Clearing Price λ (10^3\$/p.u.h)
G_1	G_2	G_3		
2.000	2.676	2.323	10.361	2.69

When reactive /voltage constraints are taken into account, the generators' active power outputs will need to be adjusted due to system voltage control requirements both in normal and contingent states. The preventive control concept is adopted in this chapter and only one potential contingency is considered. In this example, only the outage of line 4-8 will force the base case active power dispatch to be rescheduled due to the voltage constraints. Voltage profile and generation rescheduling results are given in Table 5-5 and Table 5-6, respectively.

Table 5-5. Voltage profile

Bus No.	1	2	3	4	5	6	7	8
Normal Voltage (p.u.)	1.0165	1.0000	0.9780	0.9633	0.9516	1.0025	0.9692	1.0188
Contingent Voltage (p.u.)	1.0402	1.0133	0.9868	0.9507	0.9500	1.0338	1.0042	1.0500

The voltage profile shows that no bus voltage is constrained in normal state. But in the contingency case, voltage set point of G_3 at bus 8 has to be adjusted to its upper limit and the voltage at bus 5 hits its lower limit.

Table 5-6. Generation rescheduling results

Generator	Active power Output (p.u.)	Reactive Power Capability (p.u.)	Reactive Power Output (p.u.)		Profit Loss ($/h)
			Normal	Contingency	
G_1	1.588	± 1.215	0.961	1.215	459.01
G_2	1.801	± 2.399	0.438	2.399	306.06
G_3	3.610	± 3.459	3.070	1.471	744.81

Adjusted active power generations are shown in column 2 of Table 5-6. It shows that G_1 and G_2 have to decrease their active power output for the provision of reactive power support. Due to the no loads curtailment assumption, the most expensive generator G_3 has to generate more than its base case schedule. All three generators are subject to profits losses as listed in the last column. The total active power production costs (F^c) rises up to 11.871×10^3($/h). Using equation (5-4), the system reactive power support cost is 1509.88 ($/h), which will be recovered from consumers. Column 3 shows the corresponding reactive power capabilities given active power generations listed in column 2. Reactive power outputs in normal and contingent cases are shown in columns 4 and 5, respectively. For G_1, its reactive power output is 0.961(p.u.) in normal case and hence its reserved reactive power capacity is 0.254(p.u.). This reserve would be used up if the line outage happens. A similar phenomenon applied to G_2. But the reactive power output of G_3 in the contingent case is less than that in the normal case. It is a result of reactive power support coordination among the three generators.

Following the costs allocation procedure described in the *Section 5.3*, the bisection method is first used to determine the critical demand level t_0. With a computation tolerance $\varepsilon = 0.01$, t_0 is found to be 0.875 after seven iterations. Then, the demand vector is divided into K (K is set as 200 in this example) equal parts in the effective demand level interval [0.875, 1]. Costs allocation results are given in Table 5-7.

Table 5-7. Costs allocated to consumers

Consumers	Allocation Factor		Cost Allocated ($/h)
	Real Load ($/MWh)	Reactive Load ($/MVarh)	
L_1	0.7708	1.8536	96.00
L_2	1.1332	2.1247	733.04
L_3	1.0798	2.9351	434.93
L_4	0.7468	0.8601	256.01

It can be observed from Table 5-7 that allocation factors of reactive loads (column 3) are larger than that of real loads (column 2) for all four consumers. It means that the direct reactive power consumption of each consumer is responsible for a larger part of the reactive power support costs than the indirect consumption (reactive power loss) caused by its real load. Location differences of consumers determine their different effects on reactive power support costs. In this example, the largest allocation factor among real loads appears in the consumer L_2 at bus 4 while the most effective reactive load is at bus 5. This is illustrated more clearly in Figure 5-6. Summation of the costs allocated to different consumers (column 4) is 1519.98 ($/h). The allocation error $\left(\left|\frac{1519.98-1509.88}{1509.88}\right|=0.0067\right)$ is less than one percent. This computation error will decrease if a proper value of K is used.

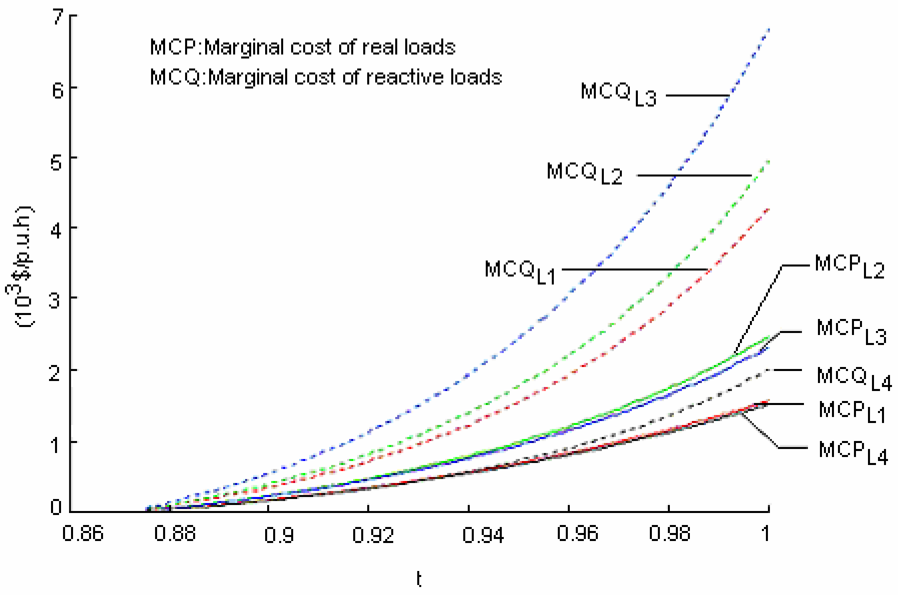

Figure 5-6. Illustration of real and reactive power marginal costs

5.5 Summary

Reactive power support from generators is critical to the system operation, and particularly to voltage security, both in traditional and deregulated power systems. Technical and economic issues related to this kind of ancillary services are examined in this chapter. The considered time horizon in this research is for operation planning. Active power rescheduling is used as a preventive control for maintaining a feasible system voltage level both in normal and contingent states. Reactive power opportunity cost of an individual generator is evaluated by its profit loss in the active power market concerned as the result of active power generation adjustment for reactive power support. The total reactive power support cost is deemed as the active power production cost increase caused by generation rescheduling, under the assumption that active transmission losses and active power market clearing price remain unchanged. Reactive power charges for consumers are calculated using the A-S cost allocation method. The bisection search algorithm is used to improve the computation efficiency. The numerical example shows that the proposed pricing scheme could ensure the total revenue from loads be equal to the total reactive power support cost. The A-S cost allocation method could lead to economically efficient outcomes since the economic signal provided by marginal cost is included. Some further research work is required for the practical implementation of the proposed methodology in operating electricity markets. More specifically, detailed generator capability models, reactive power and voltage controls from reactive power devices in the transmission system such as SVCs and capacitors need to be considered in the modeling process. Moreover, it appears necessary to study reactive power pricing for more and more popular bilateral transactions in the market environment. In addition, further enhancement of the computational speed is highly expected, if the proposed method is implemented for large-scale power systems.

6 REACTIVE POWER SERVICE COST ALLOCATION USING THE AUMANN-SHAPLEY METHOD

6.1 Introduction

As already detailed in *Chapters 4 and 5*, reactive power support is a kind of ancillary services. It is a general consensus that there should be a separate reactive power market to manage the provision of reactive power. Due to the importance of reactive power services for system reliability and the complexity of such services, a significant degree of obligation and centralized control are needed for reactive power procurement. If reactive power support is procured in the centralized way, just as the current practices in many operating electricity markets around the globe, then the issue of reactive power service cost allocation will inevitably arise. This is because the ISO takes the responsibility of procuring reactive power, and then the users must properly pay the cost of the services. However, the proper allocation of the costs concerned is not an easy task since such an allocation scheme must offer an appropriate economical signal for efficient provision and consumption of reactive power.

Different from active power, the objective of reactive power support procurement is not unique. In different power systems, the objectives could be different and are dependent on the structures and operating characteristics of the systems concerned. In addition, the constraints to be respected could also be different. All these make the problem of reactive power support cost allocations more complicated and difficult than that of active power. Generally, there does not exist an optimal scheme for the cost allocations of reactive power support, and such a scheme should be dependent on the approach used for provision. All these make it necessary to investigate the cost allocation problems under different reactive power procurement schemes so as to fit for the need of different kinds of electricity markets and associated power systems. This motivates the research work in this chapter. However, it is certainly not possible to investigate the cost allocation problems under all creditable and reasonable reactive power procurement schemes in this thesis, and as a result, only an alternative way is investigated in this chapter. Basically, the problem examined in this chapter is similar to that described in Chapter 5, but is handled from a different perspective. A different mathematical model representing a different reactive power procurement scheme is employed in this chapter. Surely, the cost allocation problem will have different characteristics under different reactive power procurement schemes.

Specifically, a centrally-managed reactive power market model is assumed where an ISO, taking into account the technical feasibility and economic efficiency, procures the required reactive power service and the incurred cost is fully allocated to all users. Reactive power OPF is used for the procurement and dispatching of reactive power services. The optimal cost of reactive power is obtained by solving two decoupled sub-problems of active and reactive power optimizations. The difficulty arises in the cost allocation process, especially in a pool-bilateral active power energy market. As in *Chapter 5,* the Aumann-Shapley method, detailed in the *Appendix B*, is also employed in this chapter, but some novel implementation techniques are introduced for the specific applications. A mathematical model of the optimization of reactive power and a description of the reactive power cost allocation problem for pool markets is illustrated in *Section 6.2*. Taking into account the direct consumption of reactive power and the indirect consumption of reactive power accompanied with the use of active power, the active load and reactive load reactive power cost allocation factors are proposed in *Section 6.3*. The discussion is extended to a pool and bilateral transactions coexisting model in *Section 6.4*. Finally, the results of a numerical simulation in a modified IEEE 14-bus system are demonstrated in *Section 6.5*.

6.2 Analysis of the Cost of Reactive Power Support

In this chapter, the optimal cost of reactive power is obtained by solving two decoupled sub-problems of active and reactive power optimizations, in sequence. The reactive power optimization is solved subsequently, after the active power optimization is completed.

- Active power optimization

$$\text{Min} \sum_{i \in NG'} C_{pg_i}(P_{g_i}) \tag{6-1}$$

subject to:

$$\sum_{i \in NG'} P_{g_i} - \sum_{j \in N} P_{d_i} = 0$$

$$P_{g_i}^{\min} \le P_{g_i} \le P_{g_i}^{\max}$$

where NG' is the set of all generator buses (except for the slack bus); $C_{pg_i}(P_{g_i})$ is the active power cost function of the generator at bus i, which is approximated as a quadratic function ($C_{pg_i}(P_{g_i}) = a + bP_{g_i} + cP_{g_i}^2$); P_{g_i} is the active power generation at bus i; N is the set of all buses; P_{d_i} is the active power load at bus i; $P_{g_i}^{\min}$ and $P_{g_i}^{\max}$ are the active power lower and upper limits, respectively, of the generator at bus i. In this model, the active power transmission loss is neglected. This optimization process can be expressed as:

$$\overline{P}_g^* = F_P(\overline{P}_d) \tag{6-2}$$

where $\overline{P}_g^* = \left[P_{g_1}^* \quad \ldots \quad P_{g_i}^* \quad \ldots \quad P_{g_{NG'}}^* \right]$ is an NG' dimensional optimal active power generation vector; $\overline{P}_d = \left\lfloor P_{d_1} \quad \ldots \quad P_{d_j} \quad \ldots \quad P_{d_N} \right\rfloor$ is an N dimensional active power load vector, and F_P is a mapping, $F_P : \overline{P}_d \rightarrow \overline{P}_g^*$.

- Reactive power optimization

The active power generation may need to be re-dispatched out of merit in order to meet the reactive power requirement. In this case, the active power problem and the reactive power problem have to be solved in an iterative way. In this chapter, it is assumed that the optimal dispatch of active power will remain unchanged when reactive power support is optimized.

Objective:

$$C_Q^* = \text{Min} \sum_{i \in NG} C_{qg_i}(Q_{g_i}) + \sum_{j \in NC} C_{c_j}(Q_{c_j}) + C_{P_{Loss}} \tag{6-3}$$

where NG is the set of all generator buses; NC is the set of all reactive compensator buses; $C_{qg_i}(Q_{g_i})$ is the reactive cost function of the generator at bus i; $C_{c_j}(Q_{c_j})$ is the reactive power cost function of the reactive power compensators at bus j; and $C_{P_{Loss}}$ is the cost of the system transmission loss.

a.) Reactive power support cost from generators

The reactive power support cost from generators is the so-called opportunity cost. The active power production capacity of a generator, which can be used in a spinning reserve market, will be reduced when providing reactive power support Q_{g_i} . This includes the production and reservation of reactive power according to the loading capability diagram of the generator. Therefore, this would cause an implicit financial loss to the generators. The following simplified reactive support opportunity cost model is used in this chapter:

$$C_{qg_i}(Q_{g_i}) = [C_{pg_i}(S_{g_i}^{\max}) - C_{pg_i}(\sqrt{(S_{g_i}^{\max})^2 - Q_{g_i}^2})]k_{g_i} \qquad (6\text{-}4)$$

where $S_{g_i}^{\max}$ is the maximum apparent power of the generator at bus i , and k_{g_i} is an assumed profit rate for active power generation at bus i , say 7%.

b.) Reactive power support cost from reactive power compensators

In this model it is assumed that reactive power compensators are owned by private investors and installed at some selected buses. The charge for using compensators is assumed to be proportional to the amount of the reactive power output purchased, and can be expressed as:

$$C_{c_j}(Q_{c_j}) = r_{c_j} Q_{c_j} \qquad (6\text{-}5)$$

where r_{c_j} and Q_{c_j} are the reactive power price and amount purchased, respectively, at location j .

c.) Cost of system transmission loss

The reactive power support will affect both the voltage profile and the transmission loss. It is assumed that the slack generator compensates for the loss of transmission. Therefore, the cost of transmission loss is:

$$C_{P_{Loss}} = C_{pg_{slack}}(P_{g_{slack}}) \qquad (6\text{-}6)$$

where $P_{g_{slack}}$ and $C_{pg_{slack}}$ are the active power output and active power cost function of the slack generator, respectively.

Constraints:

In the reactive power cost optimization, the active power outputs of generators are specified. The reactive power output of generators and compensators are the control variables. The equality and inequality constraints, including the load flow equations, reactive power output of generators and compensators, and the bus voltage limits are listed in equations (6-7)-(6-11).

$$P_{g_i}^* - P_{d_i} = \left|\dot{V}_i\right| \sum_{j \in N} \left|\dot{V}_j\right| \left|Y_{ij}\right| \cos(\theta_{ij} + \delta_j - \delta_i) \tag{6-7}$$

$$Q_{g_i} + Q_{c_i} - Q_{d_i} = \left|\dot{V}_i\right| \sum_{j \in N} \left|\dot{V}_j\right| \left|Y_{ij}\right| \sin(\theta_{ij} + \delta_j - \delta_i) \tag{6-8}$$

$$V_i^{\min} \le \left|\dot{V}_i\right| \le V_i^{\max} \tag{6-9}$$

$$Q_{c_i}^{\min} \le Q_{c_i} \le Q_{c_i}^{\max} \tag{6-10}$$

$$-\sqrt{(S_{g_i}^{\max})^2 - (P_{g_i}^*)^2} \le Q_{g_i} \le \sqrt{(S_{g_i}^{\max})^2 - (P_{g_i}^*)^2} \tag{6-11}$$

where Q_{d_i} are the specified reactive demand at load bus i ; $Y_{ij}\angle\theta_{ij}$ is the element of the admittance matrix; $\dot{V}_i = V_i\angle\delta_i$ is the bus voltage at bus i ; $V_i^{\min}$ and $V_i^{\max}$ are the lower and upper limits of the bus voltage; and $Q_{c_i}^{\min}$ and $Q_{c_i}^{\max}$ are the lower and upper limits of the reactive power output of the compensators.

The reactive power optimization problem consisting of the objective equation (6-3) and various constraints from equation (6-7) to equation (6-11) can be expressed as:

$$C_Q^* = F_Q(\overline{P}_g^*, \overline{P}_d, \overline{Q}_d) \tag{6-12}$$

where $\overline{Q}_d = \left[Q_{d_1} \quad ... \quad Q_{d_j} \quad ... \quad Q_{d_N} \right]$ and F_Q is a mapping, $F_Q : \overline{P}_g^* \times \overline{P}_d \times \overline{Q}_d \rightarrow C_Q^*$.

The SQP [65] method is used to solve this non-linear optimization problem.

- Reactive power cost allocation problem

It can be seen from equation (6-12) that the reactive power cost is related not only to the dispatch of loads but also to the dispatch of active power generation. The load side is assumed to be responsible for the total reactive power cost. Using equations (6-2), (6-12) can be rewritten as:

$$C_Q^* = F_Q(F_P(\overline{P}_d), \overline{P}_d, \overline{Q}_d) \tag{6-13}$$

This equation can be more concisely written as:

$$C_Q^* = F(\overline{X}) \tag{6-14}$$

where $\overline{X} = \left[\overline{P}_d, \overline{Q}_d \right]$ is a $2N$ dimensional loading vector. Meanwhile, the cost when there are no loads in the system ($F(\overline{0})$) is not considered in the allocation problem. Therefore, the reactive power cost that will be allocated to the loads is $C_Q = G(\overline{X}) = F(\overline{X}) - F(\overline{0})$. The question is how the cost C_Q should be allocated by the prices per unit of the active and reactive loads at each node. The pricing vector, denoted as $\overline{\eta} = [\overline{\eta}_{P_d}, \overline{\eta}_{Q_d}]$ where $\overline{\eta}_{P_d} = [\eta_{P_{d_1}} \quad \cdots \quad \eta_{P_{d_j}} \quad \cdots \quad \eta_{P_{d_N}}]$ and $\overline{\eta}_{Q_d} = [\eta_{Q_{d_1}} \quad \cdots \quad \eta_{Q_{d_j}} \quad \cdots \quad \eta_{Q_{d_N}}]$, satisfies the cost recovery requirement $G(\overline{X}) = \sum_{j=1}^{N} (\eta_{P_{d_j}} \times P_{d_j} + \eta_{Q_{d_j}} \times Q_{d_j})$.

6.3 Cost Allocation Factors for the Active and Reactive Pool Loads

Following the ideology of the A-S pricing method (detailed in the *Appendix B*), the loading vector is divided into K equal parts, $\bar{h} = \left[\bar{h}_{P_d}, \bar{h}_{Q_d}\right]$, where $\bar{h}_{P_d} = \frac{1}{K}[P_{d_1} \quad \cdots \quad P_{d_i} \quad \cdots \quad P_{d_N}]$ and $\bar{h}_{Q_d} = \frac{1}{K}[Q_{d_1} \quad \cdots \quad Q_{d_i} \quad \cdots \quad Q_{d_N}]$. We defined $\left(\bar{X}\right)^k = \left[(\bar{P}_d)^k, (\bar{Q}_d)^k\right]$, $k = 1, \cdots, K$, where $(\bar{P}_d)^k = \frac{k}{K} \cdot \bar{P}_d$ and $(\bar{Q}_d)^k = \frac{k}{K} \cdot \bar{Q}_d$. The midpoint of $\left(\bar{X}\right)^{k-1}$ and $\left(\bar{X}\right)^k$ is denoted by $\left(\bar{X}\right)^{\frac{2k-1}{2}} = \left[(\bar{P}_d)^{\frac{2k-1}{2}}, (\bar{Q}_d)^{\frac{2k-1}{2}}\right]$, where $(\bar{P}_d)^{\frac{2k-1}{2}} = \frac{2k-1}{2K} \cdot \bar{P}_d$ and $(\bar{Q}_d)^{\frac{2k-1}{2}} = \frac{2k-1}{2K} \cdot \bar{Q}_d$. The midpoint is selected as the sample point for the $k-th$ step of the reactive power support optimization, and its process is illustrated in Figure 6-1.

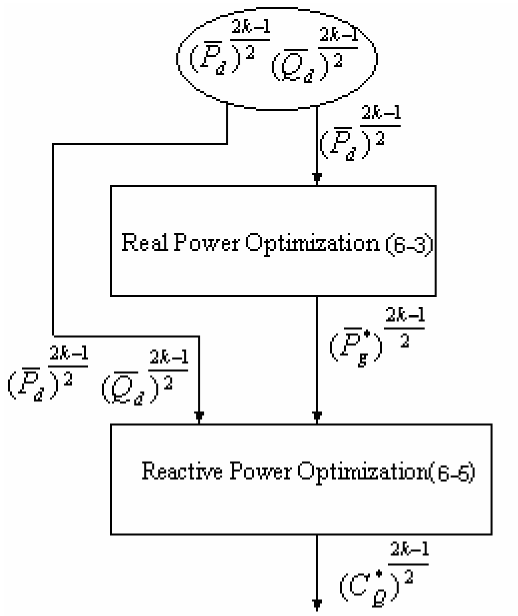

Figure 6-1. The *k-th* step of the reactive power support optimization

Using equation (B-2) in the *Appendix B*, the prices $\eta_{P_{d_i}}$ and $\eta_{Q_{d_i}}$ can be written as:

$$\eta_{P_{d_i}} = \frac{1}{K}\sum_{k=1}^{K}(\eta_{P_{d_i}})^{\frac{2k-1}{2}} \ , \ (\eta_{P_{d_i}})^{\frac{2k-1}{2}} = \frac{\partial G((\bar{X})^{\frac{2k-1}{2}})}{\partial P_{d_i}} \tag{6-15}$$

$$\eta_{Q_{d_i}} = \frac{1}{K}\sum_{k=1}^{K}(\eta_{Q_{d_i}})^{\frac{2k-1}{2}} \ , \ (\eta_{Q_{d_i}})^{\frac{2k-1}{2}} = \frac{\partial G((\bar{X})^{\frac{2k-1}{2}})}{\partial Q_{d_i}} \tag{6-16}$$

For the reactive power load Q_{d_i}, $(\eta_{Q_{d_i}})^{\frac{2k-1}{2}}$ is equal to the Lagrange multiplier $(\pi_{Q_{d_i}})^{\frac{2k-1}{2}}$ associated with the reactive power balance equation (6-8) at bus i at the midpoint of the $k-th$ step. Unfortunately, it is not that easy to obtain $(\eta_{P_{d_i}})^{\frac{2k-1}{2}}$ because a change of the active load at bus i ($h_{P_{d_i}} = \frac{P_{d_i}}{K}$) will affect the overall optimal generation of active power. From equation (6-13), $(\eta_{P_{d_i}})^{\frac{2k-1}{2}}$ should include two items as:

$$(\eta_{P_{d_i}})^{\frac{2k-1}{2}} = (\pi_{P_{d_i}})^{\frac{2k-1}{2}} - (\bar{\pi}_{P_g})^{\frac{2k-1}{2}} \times \left(\frac{\partial F_P((\bar{P}_d)^{\frac{2k-1}{2}})}{\partial P_{d_i}} \right)^T \tag{6-17}$$

where at the midpoint of the $k-th$ step, $(\pi_{P_{d_i}})^{\frac{2k-1}{2}}$ is the Lagrange multiplier associated with the active power balance equation (6-7) at bus i; $(\bar{\pi}_{P_g})^{\frac{2k-1}{2}}$ is the Lagrange multiplier vector associated with the active power balance equations (6-7) at all generator buses except for the slack bus; $\frac{\partial F_P((\bar{P}_d)^{\frac{2k-1}{2}})}{\partial P_{d_i}} = \left[\frac{\partial (P^*_{g_1})^{\frac{2k-1}{2}}}{\partial P_{d_i}} \ \cdots \ \frac{\partial (P^*_{g_j})^{\frac{2k-1}{2}}}{\partial P_{d_i}} \ \cdots \ \frac{\partial (P^*_{g_{NG'}})^{\frac{2k-1}{2}}}{\partial P_{d_i}} \right]$ is an NG' dimensional vector representing the effect of the active load at bus i on the optimal generation of active power and we denote it as $(\overline{\delta}_{P_{d_i}})^{\frac{2k-1}{2}}$ for simplicity; " T " is the vector transposing operator. The following relationship can be satisfied when the change in active loads $\overline{h}_{P_d}$ is small enough.

$$F_P((\overline{P}_d)^k) - F_P((\overline{P}_d)^{k-1}) = \overline{h}_{P_d} \times J^{\frac{2k-1}{2}} \tag{6-18}$$

where $J^{\frac{2k-1}{2}} = \begin{bmatrix} \frac{\partial (P^*_{g_1})^{\frac{2k-1}{2}}}{\partial P_{d_1}} & \frac{\partial (P^*_{g_2})^{\frac{2k-1}{2}}}{\partial P_{d_1}} & \cdots & \frac{\partial (P^*_{g_{NG'}})^{\frac{2k-1}{2}}}{\partial P_{d_1}} \\ \frac{\partial (P^*_{g_1})^{\frac{2k-1}{2}}}{\partial P_{d_2}} & \frac{\partial (P^*_{g_2})^{\frac{2k-1}{2}}}{\partial P_{d_2}} & \cdots & \frac{\partial (P^*_{g_{NG'}})^{\frac{2k-1}{2}}}{\partial P_{d_2}} \\ \vdots & \vdots & & \vdots \\ \frac{\partial (P^*_{g_1})^{\frac{2k-1}{2}}}{\partial P_{d_N}} & \frac{\partial (P^*_{g_2})^{\frac{2k-1}{2}}}{\partial P_{d_N}} & \cdots & \frac{\partial (P^*_{g_{NG'}})^{\frac{2k-1}{2}}}{\partial P_{d_N}} \end{bmatrix}_{N \times NG'}$

is the Jacobian matrix of F_P at the midpoint and its row vector is $(\overline{\delta}_{P_{di}})^{\frac{2k-1}{2}}$.

It could be seen from the active power optimization model (6-1) that the sensitivity of the optimal generation of active power to the active change in load at each bus is the same, i.e. $(\overline{\delta}_{P_{d_1}})^{\frac{2k-1}{2}} = \cdots = (\overline{\delta}_{P_{d_i}})^{\frac{2k-1}{2}} = \cdots = (\overline{\delta}_{P_{d_N}})^{\frac{2k-1}{2}}$. It is more convenient to use a common vector $(\overline{\delta})^{\frac{2k-1}{2}} = [(\delta_{P_{g_1}})^{\frac{2k-1}{2}}, \cdots, (\delta_{P_{g_j}})^{\frac{2k-1}{2}}, \cdots (\delta_{P_{g_{NG'}}})^{\frac{2k-1}{2}}]$ to denote every $(\overline{\delta}_{P_{d_i}})^{\frac{2k-1}{2}}$, where $\delta_{P_{g_j}} = \frac{\partial (P^*_{g_j})^{\frac{2k-1}{2}}}{\partial P_{d_i}}$, $\forall i \in N$. Therefore, the $j-th$ column vector of $J^{\frac{2k-1}{2}}$ is $(\delta_{P_{g_j}})^{\frac{2k-1}{2}} \times \begin{bmatrix} 1 \\ \vdots \\ 1 \end{bmatrix}_{N \times 1}$. Solving equation (6-18), we get:

$(\delta_{P_{g_j}})^{\frac{2k-1}{2}} = \dfrac{(P_{g_j}^*)^k - (P_{g_j}^*)^{k-1}}{\sum_{i=1}^{N} h_{P_{d_i}}}$ and substituting this to equation (6-17), the $k-th$ cost allocation factor of the active load at bus i can be written as:

$$
\begin{aligned}
(\eta_{P_{d_i}})^{\frac{2k-1}{2}} &= (\pi_{P_{d_i}})^{\frac{2k-1}{2}} - (\overline{\pi}_{P_g})^{\frac{2k-1}{2}} \times [(\overline{\delta})^{\frac{2k-1}{2}}]^T \\
&= (\pi_{P_{d_i}})^{\frac{2k-1}{2}} - \frac{\sum_{j=1}^{NG'} (\pi_{P_{g_j}})^{\frac{2k-1}{2}} \times [(P_{g_j}^*)^k - (P_{g_j}^*)^{k-1}]}{\sum_{i=1}^{N} h_{P_{d_i}}}
\end{aligned}
\qquad (6\text{-}19)
$$

From the above derivation, the calculation of $(\eta_{P_{d_i}})^{\frac{2k-1}{2}}$ needs two more times of active power optimization at points $(\overline{P}_d)^k$ and $(\overline{P}_d)^{k-1}$ than that of $(\eta_{Q_{d_i}})^{\frac{2k-1}{2}}$.

6.4 Cost Allocation Factors of Bilateral Transactions

The discussions in *Section 6.3* focused on the pool energy market. In this section, we will extend the discussion to a pool-bilateral market model. A bilateral transaction is a contract entered into directly between a GENCO and a DISCO. The conceptual model of a bilateral contract is one in which sellers and buyers enter into agreements where the quantities and trade prices are at the discretion of these parties and not a matter for the ISO. The chapter does not, for simplicity of presentation, consider the case where a GENCO or a DISCO contracts with several partners, but the extension is easy to formulate. We assume there are M bilateral transactions in the system besides the pool transactions. The m^{th} bilateral contract T_m is brought to the attention of the ISO, with the relevant amount of power P_{T_m} to be transferred from the sending node s_m to the receiving node r_m, where $m = 1 \cdots M$ is the index of the bilateral transactions. To ensure fairness, the order of entry should be eliminated and all bilateral transactions need to be increased at the same speed as the pool loads from zero to their full value. Similar to the loads vector, the bilateral transactions vector $\overline{P}_T = \left[P_{T_1} \quad ... \quad P_{T_m} \quad ... \quad P_{T_M} \right]_{1\times M}$ is divided into K equal parts, $\overline{h}_{P_T} = \frac{1}{K}\overline{P}_T$ and $(\overline{P}_T)^{\frac{2k-1}{2}} = \frac{2k-1}{2K}\overline{P}_T$. Here, the term of the bilateral transactions should be added to the active power equality constraint (6-7) of the reactive power optimization problem.

$P_{T_m} + P_{g_i}^* - P_{d_i} = \left|\dot{V}_i\right| \sum_{j\in N} \left|\dot{V}_j\right| \left|Y_{ij}\right| \cos(\theta_{ij} + \delta_j - \delta_i)$ when $i = s_m$, and $P_{g_i}^* - P_{d_i} - P_{T_m} = \left|\dot{V}_i\right| \sum_{j\in N} \left|\dot{V}_j\right| \left|Y_{ij}\right| \cos(\theta_{ij} + \delta_j - \delta_i)$ when $i = r_m$. The cost allocation factor η_{T_m} of T_m is $\eta_{T_m} = \frac{1}{K}\sum_{k=1}^{K} (\eta_{T_m})^{\frac{2k-1}{2}}$. The incorporation of the bilateral transaction involves changes in the injection of active power at the sending node and receiving node. Therefore, $(\eta_{T_m})^{\frac{2k-1}{2}} = (\pi_{P_{r_m}})^{\frac{2k-1}{2}}$ - $(\pi_{P_{s_m}})^{\frac{2k-1}{2}}$, where $(\pi_{P_{r_m}})^{\frac{2k-1}{2}}$ and $(\pi_{P_{s_m}})^{\frac{2k-1}{2}}$ are the Lagrange multipliers associated with the active power balance equations at bus r_m and bus s_m respectively at the midpoint of the $k-th$ step.

6.5 Simulation Results

A modified IEEE 14-Bus system is used for simulation studies. The system has 14 buses and 20 tie lines. Generators at buses 2 and 3 are active power sellers. The generator at bus 1 is selected as the slack bus and designated to make good the loss in transmission. There are two reactive power compensators installed at bus 6 and bus 8, respectively, and they are deemed to be independent reactive power suppliers. The system base capacity is 100 MVA. Data on the generators and reactive power compensators are given in Table 6-1 and Table 6-2, respectively. Transmission lines data and transformers data same as the standard data are given in Tables A-1 and A-2, respectively.

Table 6-1. Data on generators

Generator Location	Bus 1 (G_1)	Bus 2 (G_2)	Bus 3 (G_3)
Maximum Apparent Power (p.u.)	1.5	1.0	1.0
Profit Rate	0.07	0.07	0.07
Active Power Cost Function ($/hr)	$20+900P_{g_{14}}+550P_{g_{14}}^2$	$45+700P_{g_2}+430P_{g_2}^2$	$45+750P_{g_3}+450P_{g_3}^2$

Table 6-2. Data on reactive power compensators

Compensator Location	Bus 6 (C_6)	Bus 8 (C_8)
Maximum Capacity (p.u.)	0.6	0.4
Reactive Power Price ($/MVAR·hr)	.14	.10

<u>Case 1: Pool system</u>

The data on the pool loads is given in Table 6-3.

Table 6-3. Data on pool loads

Bus No.	Active power (p.u.)	Reactive Power (p.u.)
9	0.295	0.143
10	0.366	0.177
11	0.235	0.114
12	0.392	0.190
13	0.100	0.085
14	0.200	0.145

Table 6-4 gives the reactive power optimization results when all of the loads are at full value.

Table 6-4. Results of the reactive power optimization in the pool system

Reactive Power Supplier	Reactive Power Output (p.u.)	Reactive Power Cost ($/h)
G_1	0.170	1.718
G_2	0.195	2.092
G_3	0.144	1.201
C_6	0.600	8.400
C_8	0.235	2.351

The reactive power support cost in the full load case $(C_Q^*)_{Full}$, using the methodology described in *Section 6.2* is found to be 116.522$/h (the sum of the cost of all reactive power is 15.762\$/h and the cost of transmission loss is 100.761\$/h). The reactive power support cost of the no-load case (fixed cost) $(C_Q^*)_{Zero}$ is 20 \$/h. Hence, the reactive power support cost to be allocated, C_Q, is 96.522\$/h. The loading vector is divided into 20 equal intervals in this study. Figure 6-2 illustrates the changes in different cost components with the loading level. In the figure, the reactive power support costs of the generators and capacitors are amplified 10 times. The cost of transmission loss accounts for the major part of the total reactive power support cost. It can be observed that when the loads exceed 37.5 percent of their full value, the requirement of reactive power support from the capacitor at bus 6 begins to increase rapidly. This shows the importance of the reactive power support provided at bus 6 for transmission capacity.

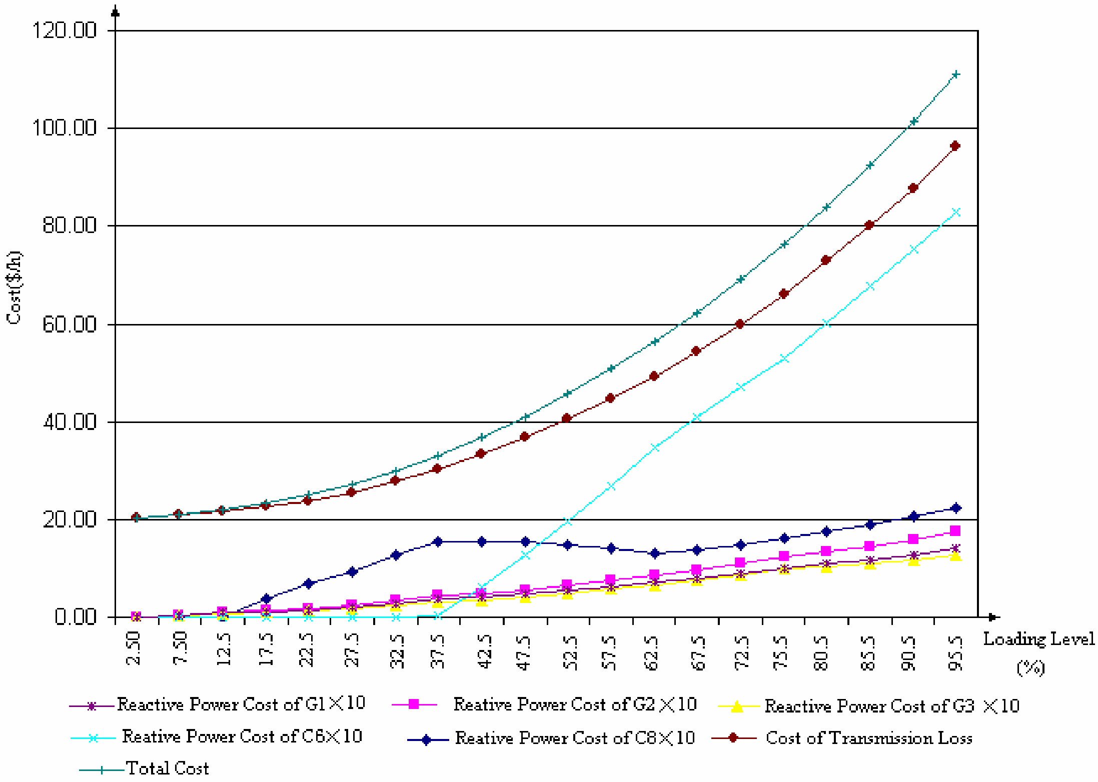

Figure 6-2. Reactive power support cost against loading level in the pool case

The results of the reactive power support cost allocation are shown in Table 6-5.

Table 6-5. Results of cost allocation in the pool system

Bus No		Allocation Factors	Cost Allocated ($/h)
9	Active Load	27.912	8.234
	Reactive Load	22.396	3.203
10	Active Load	40.765	14.920
	Reactive Load	27.309	4.834
11	Active Load	44.552	10.470
	Reactive Load	24.493	2.792
12	Active Load	64.394	25.242
	Reactive Load	30.275	5.752
13	Active Load	41.7000	4.1700
	Reactive Load	22.3242	1.8976
14	Active Load	48.149	9.628
	Reactive Load	33.233	4.819
Summation		------	95.963

Comparing the summation of allocated costs with the value of C_Q , the error is $\left|\frac{96.522-95.936}{96.522}\right| = 0.6\%$. This small error demonstrates the effectiveness and accuracy of the proposed method.

<u>Case 2: Pool –bilateral system</u>

In this case, two bilateral transactions are added to the system. The details of the bilateral transactions are given in Table 6-6.

Table 6-6. Data on bilateral transactions

Name	Sending Bus No	Receiving Bus No.	Amount of energy traded (p.u.)
T_1	4	13	0.1
T_2	5	14	0.1

Table 6-7 gives the reactive power optimization results when all of the loads are at full value.

Table 6-7. Results of the reactive power optimization in the pool-bilateral system

Reactive Power Supplier	Reactive Power Output (p.u.)	Reactive Power Cost ($/h)
G_1	0.19817	2.34021
G_2	0.22663	2.82086
G_3	0.16167	1.51406
C_6	0.60000	8.40000
C_8	0.26207	2.62073

The reactive power support cost in the full transaction case $(C_Q^*)_{Full}$ is found to be 129.14655$/h (the sum of the cost of all reactive power is 17.69585$/h and the cost of transmission loss 111.45068$/h). Compared with the pool system, this cost increase is due to the reactive power requirement needed to support the two bilateral transactions. The reactive power support cost for the no transactions case (fixed cost) $(C_Q^*)_{Zero}$ is 20 \$/h. Hence, the reactive power support cost to be allocated, C_Q, is 109.14655\$/h. Figure 6-3 illustrates the changes in different cost components with the pool loads and bilateral transactions increasing simultaneously. In the figure, the reactive power support costs of the generators and capacitors are amplified 10 times. The cost of transmission loss accounts for the major part of the total reactive power support cost.

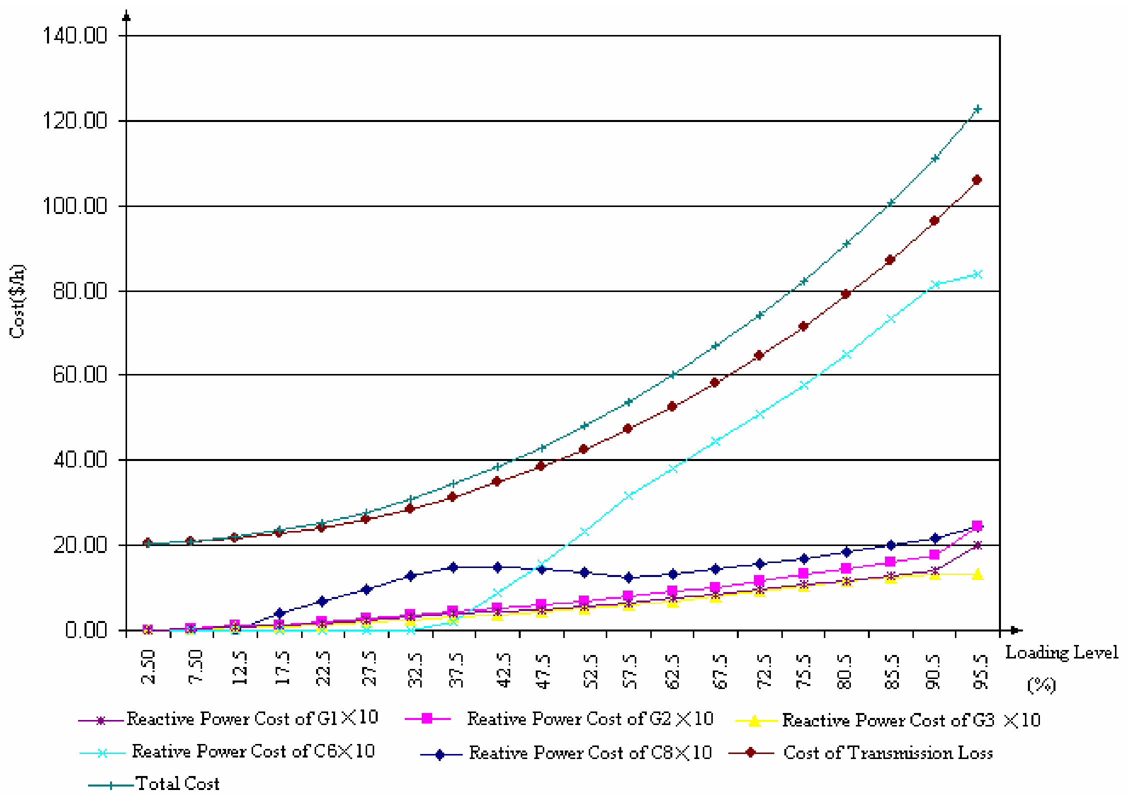

Figure 6-3. Reactive power support cost against loading level in the pool-bilateral case

The results of the reactive power support cost allocation are shown in Table 6-8.

Table 6-8. Results of cost allocation in the pool-bilateral system

Bus No.		Allocation Factors	Cost Allocated ($/h)
9	Active Load	28.29893	8.34818
	Reactive Load	23.89204	3.41656
10	Active Load	41.52505	15.19817
	Reactive Load	28.82254	5.10159
11	Active Load	45.89563	10.78547
	Reactive Load	25.75686	2.93628
12	Active Load	68.71032	26.93445
	Reactive Load	31.68291	6.01975
13	Active Load	49.88868	4.98887
	Reactive Load	23.78547	2.02177
14	Active Load	59.82405	11.96481
	Reactive Load	35.56148	5.15641
T_1		24.91251	2.49125
T_2		34.22045	3.42205
Summation		------	108.78561

The cost allocated to the bilateral transactions is about 5.91$/h. This cost is less than half of the cost increase of 12.62$/h as a result of adding the bilateral transactions. It indicates that no priority is granted to the pool loads because the factor of order of entry is eliminated in the A-S method. Each consumer is treated equally in this sense. Comparing the summation of the allocated costs with C_Q, the error is $\left|\frac{109.147-108.786}{109.147}\right| = 0.3\%$. Compared with the error in the pool system case, it shows that the accuracy of cost allocation will not decrease when there are more participants in the allocation process. The accuracy of the A-S allocation is independent of the dimension of the problem.

6.6 Summary

The cost allocation for reactive power support in the electricity market environment is investigated in this chapter from a different perspective. In other words, a different objective from that in *Chapter 5* for procuring reactive power support is employed in this chapter. Based on the economic dispatch of active power, the reactive power optimization minimizes the summation of the reactive power support costs from different reactive power suppliers and the cost of transmission losses. This minimum cost is then allocated to different consumers using Aumann-Shapley prices. Active and reactive loads are responsible for the reactive power support costs in pool-type systems. The effects of the active generations are accounted to the allocation factors of active loads. In pool-bilateral co-existing systems, the pool loads and bilateral transactions are treated equally because the cost allocation factors are calculated in the same framework. No priority is granted to any transactions. The numerical example shows that the proposed allocation scheme ensures that the total revenue from the loads be equal to the total reactive power support cost. Computation speed is a critical issue when applying the proposed methodology to large systems. The main computation burden lies in the reactive power optimization as represented by equation (6-13). Some measures for improving the computational efficiency could be employed such as the use of fast non-linear techniques with variable step lengths.

7 REACTIVE POWER OPTIMIZATION WITH VOLTAGE STABILITY CONSIDERATION IN ELECTRICITY MARKET ENVIRONMENT

7.1 Introduction

In the last three chapters, some important issues concerning reactive power support in the electricity market environment have been investigated, including a reactive power management framework and reactive power cost allocation methods. Without doubt, an important function of reactive power support is to ensure voltage stability, and this is true both in the traditional vertically integrated power industry and in the restructured system. Hence for reactive power scheduling, in addition to the cost minimization such as loss minimization, in some cases it is necessary to take voltage stability into account. This is the problem of so-called reactive power optimization with voltage stability constraints.

While quite a lot of research work has already been carried out for the reactive power optimization problem with voltage stability constrains respected for the traditional power system, less attention has been paid to the same problem in the electricity market environment. However, the problem may be more complicated and challenging in the new environment. This is because in the past transmission systems were owned by regulated and vertically integrated utility companies. They have been designed and operated so that conditions in close proximity to security boundary were not frequently encountered. However, in the new open access environment, operating conditions tend to be much closer to security boundaries. This is because transmission use is increasing in sudden and unpredictable directions, as a result of bid-based dispatching and long-distance transactions. Transmission unbundling has made new transmission investment more difficult, mainly due to regulatory uncertainties. Hence, there is an acute need for research work in the new market structure, especially in the areas of voltage security and reactive power support. It is well known that reactive power plays a very important role in supporting active power transfers and maintaining proper voltage profiles. This support becomes especially important when an increasing number of transactions are using a transmission system and the voltage problem causes a bottleneck discouraging additional power transfers. As electric utilities attempt to maximize the uses of their transmission system capacities to transfer active power, voltage collapse could become a limiting factor. In order to transport more active power and improve voltage stability the design of optimal reactive power support to prevent voltage collapse is important. Although some papers have been published on reactive power related issues in the market environment, their objectives are more or less focused on the procurement and cost allocations of reactive power support. To the best of our knowledge, no publications are available on the problem of reactive power optimization with voltage security taken into account.

Given this background, a systematic method is presented in this chapter to optimize reactive power support in electricity market environment with voltage stability requirement taken into account, while relying on the basic concepts of opportunity cost and reactive power compensators remuneration introduced in [32][33][78][92][114]. Voltages and reactive power support are inextricably linked and the role of reactive power support is to maintain a proper voltage profile. In an open electricity market, reactive power support could be deemed as a kind of important ancillary services for active power transportation, as already mentioned in the previous chapters. The cost and price analysis of such support needs to be established for the market to function properly. This chapter integrates cost analysis and voltage stability analysis using an optimal power flow formulation, which is solved using the sequential quadratic programming method. Similar to *Chapter 4*, in this chapter reactive power cost is considered coming from two main sources: generator and reactive power compensation equipment. At present, the cost of reactive power support in the transmission system is usually recovered from transmission charge. However it is widely agreed that, in order to improve the competence in the design of the future reactive power market, reactive power support from compensators should be treated as a part of reactive power ancillary services and its cost recovery should be separated from transmission charges. Independent reactive power producers are expected to emerge as important players in the new power market. The costing models from these two kinds of reactive power sources are described in detail in *Chapter 4* and will not be repeated here. The method presented in this chapter incorporates voltage stability constraints and reactive power cost minimization in a unified OPF formulation, and both reactive power costs from generators and reactive power compensators are included. Voltage stability margin requirements constraint is explicitly included the reactive power optimization problem. The proposed methodology is finally tested on the IEEE 14-bus system.

7.2 Optimization Method for Static Voltage Stability Problem

The static indices for voltage stability developed in the past decades can be divided into two types, sensitivity-type and margin-type. Sensitivity-type indices consider infinitesimal load perturbation and use system linearization through the Jacobian matrix.

Such indices suffer from the major non-linearities imposed by reactive power limitations [51][80]. Margin-type indices aim at directly locating the operating point with respect to the critical point for different ways of increasing the load. This work selects a loading limit known as the *voltage stability margin* (VSM), which is defined as the difference between the maximum load (corresponding to the voltage collapse point) and the base-case load at a given set of buses, as the index of interest. Given a direction of system stress, the loading limit indicates how much the system can be stressed before becoming unstable. The concept of ‘a direction of stress’ refers to the way in which load (generation) values are incremented at the load (generation) buses. The VSM concept is illustrated in Figure 7-1 for single bus case.

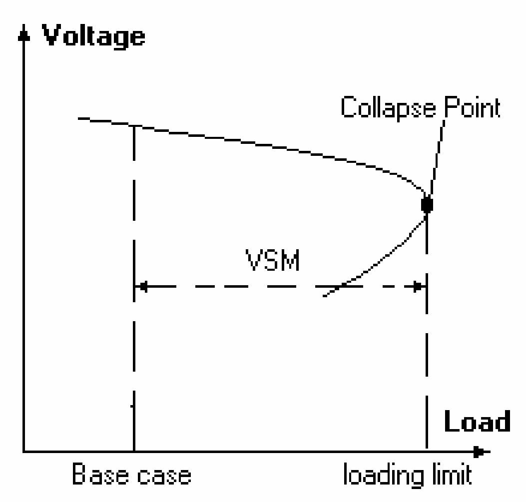

Figure 7-1. Voltage stability margin illustration

One class of methods for determining the loading limit, which tracks the system state as loads increase, is the continuation power flow method which circumvents the problem that traditional power flows fail to converge or converge unreliably around the collapse point (owing to the singularity of the Jacobian matrix). Another class, which is adopted here, is the optimization-based method where the collapse point is determined by maximizing the loads in an area of the system with power system constraints. The main advantage of the optimization-based method is that it can efficiently incorporate system equipment limits (e.g. generator VAR limits and transformer tap settings) as inequality constraints.

Loading increases and equipment outages are two causes of voltage instability. The voltage instability limit is approached gradually as loading increases and it may be possible for the system operator to detect it and take control action to prevent system collapse. The latter (line and generator outages) causes the stable domain to shrink immediately which can lead to sudden voltage collapse. The threat of such sudden collapse is more serious. Hence the network models to be examined should include the contingent cases.

Now making an assumption that only increasing active power loads and corresponding active generations stress the system while reactive power demands remain constant, the optimization model for VSM analysis is written as:

$$\text{Max } \Delta P_{Total} \tag{7-1}$$

subject to:

$$P_{gi}^{0} + \beta_{gi}\Delta P_{Total} = \left|\dot{V}_i\right| \sum_{j\in N} \left|\dot{V}_j\right| \left|Y_{ij}\right| \cos(\theta_{ij} + \delta_j - \delta_i)$$

$$-P_{Li}^{0} - \lambda_{Li}\Delta P_{Total} = \left|\dot{V}_i\right| \sum_{j\in N} \left|\dot{V}_j\right| \left|Y_{ij}\right| \cos(\theta_{ij} + \delta_j - \delta_i)$$

$$Q_{gi} = \left|\dot{V}_i\right| \sum_{j\in N} \left|\dot{V}_j\right| \left|Y_{ij}\right| \sin(\theta_{ij} + \delta_j - \delta_i)$$

$$-Q_{Li}^{0} = \left|\dot{V}_i\right| \sum_{j\in N} \left|\dot{V}_j\right| \left|Y_{ij}\right| \sin(\theta_{ij} + \delta_j - \delta_i)$$

$$V_{gi,\min} \le \left|\dot{V}_{gi}\right| \le V_{gi,\max}$$

$$Q_{gi,\min} \le Q_{gi} \le Q_{gi,\max}$$

where N is the total number of buses in the system; P_{gi}^{0} is the active power output at generator bus i in the base-case; similarly P_{Li}^{0} and Q_{Li}^{0} are the active and reactive demand at load bus i in the base-case; Q_{gi} is the reactive power output of generator at bus i; $Y_{ij}\angle\theta_{ij}$ is the element of the admittance matrix; $\dot{V}_i = V_i\angle\delta_i$ is the bus voltage at bus i ; $V_{gi,\min}$ and $V_{gi,\max}$ the lower and upper limits of generator bus voltage; $Q_{gi,\min}$ and $Q_{gi,\max}$ the lower and upper limits of reactive power output of the generator; ΔP_{Total} is the total increase of system active load; λ_{Li} is a distribution factor which defines how much of the load increase occurs at bus i while β_{gi} is a similarly defined participation factor for generator i.

It should be noted that:

1. The solution of the optimization problem (7-1) corresponds to the voltage collapse point.

2. The solution only gives the maximum active load increase limited by generator reactive power limits and network structure.

3. Generator buses are treated as voltage controllable nodes within a permitted voltage range.

4. For a given load increase zone Z, the sum of distribution factors λ_{Li} and the sum of generator participation factors β_{gi} are unity ($\sum_{Li\in Z}\lambda_{Li} = 1$, $\sum \beta_{gi} = 1$). Furthermore, β_{gi} is decided by the corresponding load distribution factor(s) as

follows. The generator participation factor and the load distribution factor of a bilateral transaction pair are equal. For a pool generator, β_{gi} is set to be $\beta_{Gi} = \frac{P_{gi}^0}{\sum_{gi \in PoolGenerators} P_{gi}^0} \sum_{Li \in PoolLoads} \lambda_{Li}$. Given every λ_{Li} and β_{gi} , the direction of system stress is defined.

5. It is assumed that the reference generator compensates transmission line loss changes.

7.3 Optimization of Reactive Power Support

Transmission systems owned by regulated, vertically integrated utility companies are designed and operated so that conditions in close proximity to security boundary were not frequently encountered. With increased energy use in the deregulated environment, the power system is experiencing greater level of power transfers but in many countries transmission reinforcements are not keeping pace. This is because private investment in generation seems to be popular but sometimes there is no clear mandate about the transmission side. Hence maintaining adequate security margins to ensure reliable operation is a necessary concern in these cases. Voltage stability requires the power system to retain a margin of power to ride through a perturbation on the system and still remain synchronism. Setting voltage limits at buses may not be able to serve this function. The purpose of reactive power dispatch is to determine the proper amount and location of reactive power support in order to maintain a proper voltage profile and voltage stability requirement. In an open market system the costs and contribution of different reactive power facilities should be more precisely evaluated.

7.3.1 Basic optimization model

The methodology presented here is cost-based and the model takes the loadability limit into account as a constraint. It can be formulated as a NLP problem:

$$\text{Min } \Delta C_Q \tag{7-2}$$

subject to:

$$g(x) = 0$$
$$h(x) \le 0$$
$$VSM \ge VSM^{DEF}$$

The objective function ΔC_Q is the reactive power cost increase when considering the voltage stability problem as shown in problem (7-1) whose detailed expression will be given later. The equality constraint $g(x)$ is the set of system power flow equations while $h(x)$ is the usual set of inequality operation constraints such as voltage magnitude limits and lower and upper bounds on reactive power production. The last constraint refers to voltage security and its meaning will become clear in the next section (VSM^{DEF} is a predefined minimum limit.). The problem looks like an ordinary NLP at first glance but is in fact different because the voltage stability margin (the last constraint) cannot be expressed explicitly using system parameters as $g(x)$ and $h(x)$ can. It is necessary to adopt an iterative approach to solve this problem. However it is not easy to obtain convergence since VSM is itself a complicated sub-problem. Hence we have to modify the model to a more practical problem solving approach.

7.3.2 Modification of the model

The problem formulated in (7-2) could be described as a two-objective optimization problem with the addition of controllable reactive power injections. One objective is the minimization of cost and another is the maximization of VSM, which has a minimum requirement (VSM^{DEF}). Since it can be reasonably expected that the improvement of the second goal, maximization of VSM, will lead to an increase of the reactive power cost the optimal point for problem (7-2) will appear on the boundary of VSM= VSM^{DEF}. The equality constraints $g(x)$ uses a style similar to problem (7-1). Referring back now to the approach introduced in *Section 7.2*, the maximum potential active power can be taken as the index of VSM and ΔP_{Total}, the active power balance constraint of problem (7-1), can be directly replaced by VSM^{DEF}. For reactive power balance constraints, available reactive power injections should be added. The lower and upper limits of such injections should also be added to the system inequality constraints $h(x)$. All the needed relationships are now available for formulating the optimization problem. The modified model of (7-2) is written as follows:

$$\text{Min } \Delta C_Q \tag{7-3}$$

subject to:

$$P_{gi}^0 + \beta_{gi} VSM^{DEF} = \left|\dot{V}_i\right| \sum_{j\in N} \left|\dot{V}_j\right| \left|Y_{ij}\right| \cos(\theta_{ij} + \delta_j - \delta_i)$$

$$-P_{Li}^0 - \lambda_{Li} VSM^{DEF} = \left|\dot{V}_i\right| \sum_{j\in N} \left|\dot{V}_j\right| \left|Y_{ij}\right| \cos(\theta_{ij} + \delta_j - \delta_i)$$

$$Q_{gi} = \left|\dot{V}_i\right| \sum_{j\in N} \left|\dot{V}_j\right| \left|Y_{ij}\right| \sin(\theta_{ij} + \delta_j - \delta_i)$$

$$\Delta Q_{Li} - Q_{Li}^0 = \left|\dot{V}_i\right| \sum_{j\in N} \left|\dot{V}_j\right| \left|Y_{ij}\right| \sin(\theta_{ij} + \delta_j - \delta_i)$$

$$V_{gi,\min} \le \left|\dot{V}_{gi}\right| \le V_{gi,\max}$$

$$Q_{gi,\min} \le Q_{gi} \le Q_{gi,\max}$$

$$\Delta Q_{Li\min} \le \Delta Q_{Li} \le \Delta Q_{Li\max}$$

where all variables are the same as problem (7-1) and problem (7-2) except that ΔQ_{Li} is the possible reactive power injection increase at load bus *i* and $\Delta Q_{Li\min}$ ($\Delta Q_{Li\max}$) stands for the corresponding lower (upper) limit. The objective function (detail discussions can be found in *Section 4.2*) is given as:

$$\varDelta C_Q = \sum \left[C_{gpi}(\sqrt{S_{gi\max}^2 - Q_{gi}^{0^2}}) - C_{gpi}(\sqrt{S_{gi\max}^2 - Q_{gi}^2}) \right] k_{gi} + \sum r_{Li} \Delta Q_{Li} \qquad (7\text{-}4)$$

The following points should be noted:

- Problem (7-3) now overcomes the implicit inequality constraint contained in (7-2) and discussed previously. This is also the reason why an optimization method for voltage stability analysis can be directly employed in this chapter instead of repetitive solution methods.

- The objective function is expressed as the reactive power cost increase. Such increase will change the initial reactive power dispatch that may not consider the voltage problem or the change of system operation like line (or generator) outages. When these factors are taken into account, the system operator needs to re-dispatch the reactive power for a predefined voltage stability requirement.

- A feasible domain may not exist if available reactive power support is not adequate to satisfy the voltage inequality constraints under heavy loading conditions. Even without reactive power constraints, the required margin (VSM^{DEF}) may not be satisfied because of basic system operating or structural parameter constraints. In this chapter, we assume that VSM^{DEF} defined by the system operator can be reached using available reactive power support.

- Admittance matrix should be correspondingly modified for different line outage cases.

- The solution of (7-3) including state variables (voltage, active and reactive power output of generators) and control variables (controllable reactive power injection) corresponds to the values at the optimal point.

- There is no general method to solve the NLP problem. Here the SQP method [65] is adopted. The details of the method can be found in *Section 4.3.2*.

7.4 Simulation Results

The modified IEEE 14-Bus system (*see Appendix A*) is used for computer simulation studies. The system has 5 generators, 14 buses and 20 tie lines. The generator at bus 1 is selected as the slack bus and designated to make good the loss in transmission and its reactive power cost is not included in the optimization procedure. The system base capacity is 100 MVA. The character of the system is that power is sent from the generation area (generators on bus 2 and bus 3) to the main load center through long transmission lines. The zone in which the loads increase are bus 13 and bus 14. Other loads outside the zone are fixed. Load at bus 13 has an individual bilateral contract with the generator at bus 2 while the load at bus 14 buys power from the generator at bus 3. Hence the system stress model can be defined when the loads distribution and generators participation factors are specified. The distribution factors of load 13 and load 14 ($\lambda_{L13}, \lambda_{L14}$) are set equal to 0.5 each. According to the discussion in *Section 7.2*, the participation factors of generator 2 and 3 (β_{G2}, β_{G3}) are both 0.5.

Generator data, which are usually used for reactive power opportunity cost analysis, are given Table 7-1. Transmission lines data and transformers data same as the standard data are given in Tables A-1 and A-2, respectively.

Table 7-1. Data on generators for reactive power support cost analysis

Generator Location.	Bus 2(G_2)	Bus 3(G_3)	Bus 6 (G_6)	Bus 8(G_8)
Maximum Apparent Power (p.u.)	0.8	0.8	0.5	0.5
Active Power Output (p.u.)	.150	.150	.112	.300
Reactive Power Limit (p.u.)	[-0.4,0.5]	[-0.5,0.4]	[-0.06,0.24]	[-0.06,0.24]
Profit Rate	0.07	0.07	0.07	0.07
Active Power Cost Function ($/hr)	$45+750P_i+450P_i^2$			

Without any compensators installed, VSMs for different cases, the corresponding generator reactive power outputs and system reactive power costs are given in Table 7-2. The last column gives the maximum VSM values obtained from solving problem (7-1).

Table 7-2. VSMs and reactive power cost without installing compensators

Operating Condition	Buses connected to an outage line		Reactive Power Output (p.u.)				Total Cost($/hr)	VSM
	From	To	G_2	G_3	G_6	G_8		
Normal	--	--	-.010	-.175	.001	.172	4.52	.834
Single Line Outage	4	9	-.013	-.176	.001	.179	4.79	.746
	6	13	.001	-.165	-.030	.200	5.29	.363
	7	9	.000	-.168	.069	.132	3.69	.522

Assuming that the defined loadability for the normal case (VSM^{DEF}) is 1.0 and that it should be 80% of the normal case when single line outage occurs, the VSM column of Table 7-2 shows that the reactive power dispatch capability does not meet the requirement. Compensators need to be installed to improve the voltage stability margin and we select buses 4, 5 and 10 as candidates for compensator installation. Capacity and depreciation coefficient of selected compensators are listed in Table 7-3.

Table 7-3. Depreciation rate of candidate compensators

Compensator Location	Bus 4(C_4)	Bus 5(C_5)	Bus 10 (C_{10})
Maximum Capacity	0.3	0.3	0.3
Depreciation Coefficients ($/$MVAR$·hr)	.07	.05	.10

The results obtained by the optimization model (7-3) or minimum reactive power cost increases are given in Table 7-4. In all these cases VSM now satisfies the condition VSM≥1.0 for the normal case and VSM≥0.8 for the outage cases.

Table 7-4. Minimum reactive power cost increase vs. contingencies

Operating Condition		Normal	Single Line Outage		
Buses connecting the outage line	From	--	4	6	7
	To	--	9	13	9
Loadability Requirement		1	0.8	0.8	0.8
Generator Reactive Power Output (p.u.)	G_2	0.033	0.048	0.035	0.047
	G_3	-0.234	-0.216	-0.211	-0.216
	G_6	0.143	0.059	0.87	0.117
	G_8	0.168	0.158	0.24	0.168
Required Capacity (p.u.)	C_4	0.0	0.0	0.0	0.0
	C_5	0.051	0	0.177	0.124
	C_{10}	0.3	0.3	0.3	0.3
Minimum Cost Increase ($/hr)		6.56	3.84	7.24	6.67

Table 7-5 gives the cost increases with various loadability (VSM^{DEF}) requirements for the normal operating condition.

Table 7-5. Minimum reactive power cost increase vs. loadability requirements

Loadability Requirement (p.u.)	Generator Reactive Power Output (p.u.)				Required Capacity (p.u.)			Minimum Cost increase ($/hr)
	G_2	G_3	G_6	G_8	C_4	C_5	C_{10}	
1.0	.033	-.234	.143	.168	.000	.051	.300	6.56
1.1	.014	-.247	.170	.175	.000	.144	.300	8.26
1.2	-.008	-.259	.197	.182	.000	.248	.300	10.28
1.3	-.009	-.264	.240	.193	.003	.300	.300	12.71
1.4	-.100	-.326	.240	.174	.290	.300	.300	17.34

It can be observed that reactive power cost increases, at a non-linear rate, with the higher loadability requirements. In a practical system it is necessary to examine several important contingent cases. The methodology however is a repetition of what has been presented above.

7.5 Summary

A novel methodology for reactive power dispatch is presented in this chapter with voltage stability requirement taken into account. Both voltage stability and minimum reactive power cost requirement are solved in one unified optimisation model. Optimum reactive power dispatch schemes are obtained under various voltage stability margin requirements in both normal and outage conditions. The minimization of the reactive power cost, which includes opportunity cost of generators and remuneration to owners of reactive power compensator, provides an economic means of dispatching reactive power support. The effectiveness of the proposed method has been demonstrated through simulation studies. It can be seen from the results that reactive power compensators play an important role in maintaining the system voltage profile. Obviously, reactive power cost will increase with higher voltage stability margin requirements.

8 CONCLUSIONS

8.1 Main Contributions

The main contributions of this PhD thesis are summarized as below:

1) In *Chapter 2*, an optimal generation rescheduling approach for transient security enhancement under a single contingency in an open access market environment is developed. The approach relies on a stability index, i.e. the so-called CTEM computed by the corrected hybrid method, which bears a linear relationship to certain system operating variable changes such as power exchanges between generators or bilateral contract curtailments. Transient security enhancement for one potential unstable contingency is formulated as a simple linear optimization problem with the objective of minimum deviation from original market-based operating point. To some extent, the developed method actually represents a dynamic security auction mechanism.

2) A generalized approach for transient security enhancement under multiple contingencies is developed for deregulated power systems in *Chapter 3*. A global index is first developed which can affect the global stability enhancement and deal with trade-off problem for multi-contingency condition. Then, a technically sound and economically fair approach is developed to optimize the generation rescheduling scheme for the cases that several potentially unstable contingencies are taken into consideration. The approach is especially useful when there does not exist a scheme which could sustain all creditable contingencies. Finally, simulation

studies demonstrate that the proposed approach is compatible with the new deregulated competitive market structure.

3) In *Chapter 4*, a centralized market model for reactive power management is developed. Basically, a cost based mechanism is employed in the proposed scheme. First, a modified reactive OPF model is developed to solve the optimal reactive power dispatch problem. Reactive power responsibilities are equitably shared and priced among generators and loads concerned. Specifically, the total reactive power support cost is separated into generators' duty and loadings' duty. Cost duty on the generation side is allocated to active power sellers by evaluating their reactive power requirements for active power transportations. The evaluation method adopted has a common basis for every market participant and hence it is consistent and equitable. Each generator will be paid according to the difference between its actual incurred cost in reactive power support and its cost of reactive power requirement for its own active power transportations. Charges for reactive loads consider both locations and the amounts of reactive power demands. The proposed model and method are demonstrated through an IEEE system. The results obtained illustrate that the proposed transparent reactive power management scheme is compatible with the new competitive market structure, and economic efficiency could be achieved.

4) Reactive power support from generators is critical to the system operation, and particularly to voltage security, both in traditional and deregulated power systems. In *Chapter 5*, both technical and economic issues related to this kind of ancillary services are examined. The considered time horizon in this research is for operation planning. Active power rescheduling is used as a preventive control for maintaining a feasible system voltage level both in normal and contingent states.

Reactive power opportunity cost of an individual generator is evaluated by its profit loss in the active power market concerned as the result of active power generation adjustment for reactive power support. The total reactive power support cost is deemed as the active power production cost increase caused by generation rescheduling, under the assumption that active transmission losses and active power market clearing price remain unchanged. Reactive power charges for consumers are calculated using the Aumman-Shapley cost allocation method. The bisection search algorithm is used to improve the computation efficiency. The numerical example shows that the proposed pricing scheme could ensure the total revenue from loads be equal to the total reactive power support cost. The Aumman-Shapley cost allocation method could lead to economically efficient outcomes since the economic signal provided by marginal cost is included.

5) In *Chapter 6*, a similar problem as in *Chapter 5*, i.e, the cost allocation for reactive power support in the electricity market environment, is investigated from a different prospect. In other words, a different objective from that in *Chapter 5* for procuring reactive power support is employed in this chapter. Based on the economic dispatch of active power, the reactive power optimization minimizes the summation of the reactive power support costs from different reactive power suppliers and the cost of transmission losses. This minimum cost is then allocated to different consumers using Aumann-Shapley prices. Active and reactive power loads are responsible for the reactive power support costs in pool-type systems. The effects of the active generations are accounted to the allocation factors of active loads. In pool-bilateral co-existing systems, the pool loads and bilateral transactions are treated equally because the cost allocation factors are calculated in the same framework. No priority is granted to any transactions. The numerical

example shows that the proposed allocation scheme ensures that the total revenue from the loads be equal to the total reactive power support cost.

6) A novel methodology for reactive power dispatch is presented in *Chapter 7* with voltage stability requirement taken into account. Both voltage stability and minimum reactive power cost requirement are solved in one unified optimisation model. Optimum reactive power dispatch schemes are obtained under various voltage stability margin requirements in both normal and outage conditions. The minimization of the reactive power cost, which includes opportunity cost of generators and remuneration to owners of reactive power compensator, provides an economic means of dispatching reactive power support. The effectiveness of the proposed method has been demonstrated through simulation studies.

8.2 Directions for Future Research

1) In the developed transient security enhancement methods for the electricity market environment as detailed in *Chapters 2 and 3*, the sensitivity of the stability margin with respect to active power shifts is computed for once only based on the given basic operating state. Rigorously speaking, this sensitivity should be updated if active power shifts are enforced.

2) In reactive power management in the electricity market environment, appropriate determination of the obligation for reactive power support from generators is still an important issue to be investigated further.

3) In procuring reactive power support services, it appears necessary to consider multiple possible future operating scenarios in determining the proper amount of reactive power procurement as so to maximize the benefits. For this purpose, a

probabilistic method could be employed to take into account of the possibilities of different operating scenarios.

4) The problem of reactive market power is an important issue and is of different features from those of active market power. Although some research work has already been done on the reactive market power assessment, the problem is still far from well solved.

5) The problem of how to procure reactive power support service in the electricity market environment, by a bid-based competitive market or through other ways, has been extensively debated. As expected, such debates will continue. For resolving such debates, in-depth research, especially in detailed comparison, appears very demanding.

6) Opportunity cost is a very important concept in procuring reactive power support services in the electricity market environment. However, how to properly determine the opportunity cost of a generator is still a problem not well solved and future research is demanding, especially in the centralized procurement mode.

7) In the proposed methods in described in *Chapters 5 and 6*, further enhancement of the computational speed is highly expected, if they are implemented for large-scale power systems.

APPENDIX A IEEE 14-BUS SYSTEM

A single line diagram of the IEEE 14-bus system [56] is shown in Figure A-1.

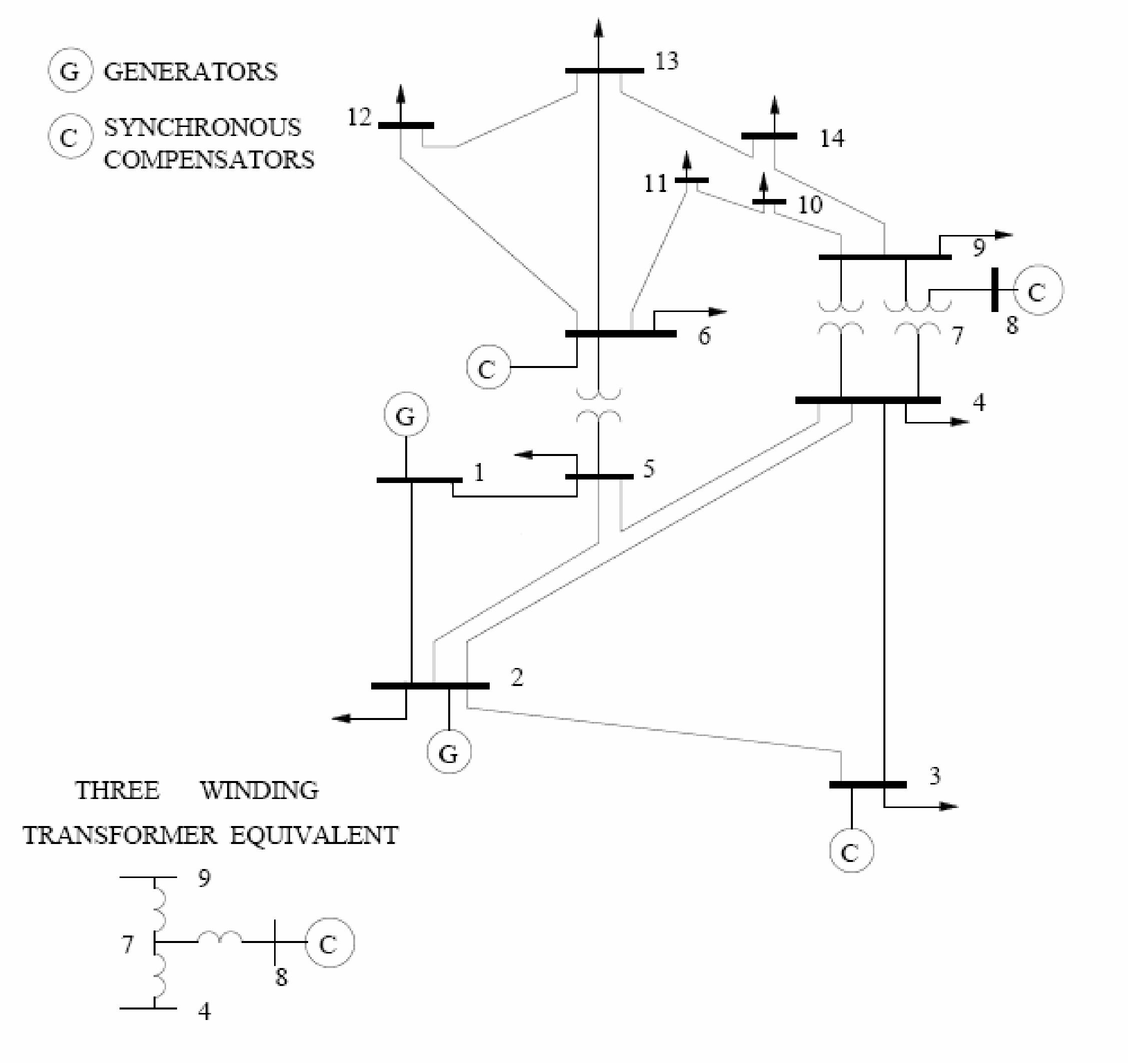

Figure A-1. IEEE 14-bus system

Transmission lines data and transformers data are listed in Tables A-1 and A-2, respectively. The system base capacity is 100 MVA.

Table A-1. Transmission lines data of the IEEE 14-bus system

From Bus	To Bus	Resistance (p.u.)	Reactance (p.u.)	Line charging (p.u)
1	2	0.01938	0.05917	0.0528
1	5	0.05403	0.22304	0.0492
2	3	0.04699	0.19797	0.0438
2	4	0.05811	0.17632	0.0374
2	5	0.05696	0.17388	0.0340
3	4	0.06701	0.17103	0.0346
4	5	0.01335	0.04211	0.0128
6	11	0.09498	0.19890	0.0000
6	12	0.12291	0.25581	0.0000
6	13	0.06615	0.13027	0.0000
7	8	0.00000	0.17615	0.0000
7	9	0.00000	0.11001	0.0000
9	10	0.03181	0.08450	0.0000
9	14	0.12711	0.27038	0.0000
10	11	0.08205	0.19207	0.0000
12	13	0.22092	0.19988	0.0000
13	14	0.17093	0.34802	0.0000

Table A-2. Transformers data of the IEEE 14-bus system

From	To	Resistance (p.u.)	Reactance (p.u.)	Tap Ratio (p.u.)
4	7	0	0.20912	0.978
4	9	0	0.55618	0.969
5	6	0	0.25202	0.932

APPENDIX B THE AUMANN-SHAPLEY COST ALLOCATION METHOD

Cost allocation problems arise in many contexts in economics and management science. In a typical problem that we have in mind, a decision maker must decide how to allocate the joint cost of service among several users, using prices. Furthermore, these prices must satisfy certain reasonable postulates, among which is the requirement that the total revenue associated with these prices must cover the total cost. This requirement can be expressed as: $F(\alpha)=\sum_{i=1}^{M}\eta_i\alpha_i$, where *F*( ) is the cost function (*F*(0)=0); $\alpha=(\alpha_1,\alpha_2,\cdots,\alpha_M)$ is an *M* dimensional vector of the quantities consumed; η_i is the cost allocation factor (price) related to the *i-th* user. Billera, Heath, and Raanan [12]) first applied the value concept of nonatomic games studied by Aumann and Shapley to solve an internal telephone-billing problem. A-S method has been applied to many areas such as transportation cost allocation [105], risk management [37] and transmission loss cost allocation [117]. It has become a strong tool for joint cost allocation due to properties of economic efficiency, fairness and robust.

It has been shown in [11][91] that A-S prices are uniquely determined by a set of neutral and, in a sense, equitable axioms imposed on price mechanisms. The axioms and relevant economic interpretations are given by:

(A.1) (Cost sharing): The generated revenue exactly recovers the total cost.

(A.2) (Additivity): The price based on the total cost function is equal to the sum of the prices computed with respect to the (additive) components of the cost function.

(A.3) (Positivity): The demand of a consumer actually contributes to total costs should have non-negative price.

(A.4) (Rescaling): A (linear) change in the units of measurement of the demand results in a concomitant change in the price.

(A.5) (Consistency): Two consumers that have the same effect on the cost function should be charged the same price.

Rather than using game theoretic notions, these axioms involving only cost functions and quantities consumed are stated in purely economic terms, hence providing an economic justification for using A-S prices. Using the formula in [11], the A-S price related to the *i-th* user (η_i^{AS}) is written as:

$$\eta_i^{AS}(F,\alpha) = \int_0^1 \frac{\partial F}{\partial x_i}(\lambda\alpha)d\lambda \qquad \text{(B-1)}$$

With the application of the mid-point rule, we can rewrite (B-1) as:

$$\eta_i^{AS}(F,\alpha) = \frac{1}{K}\sum_{k=1}^{K}\frac{\partial F}{\partial x_i}\left(\frac{2k-1}{2K}\alpha\right) \qquad \text{(B-2)}$$

where K is the number of numerical integration steps.

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